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Government of the Province of Alberta

THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD

Report with respect to applications now before the Board for permission to remove gas or cause it to be removed from the Province under the provisions of The Gas Resources Preservation Act.

MARCH 29, 1952

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PROVINCE OF ALBERTA

THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD

REPORT

With Respect to the Applications under The Gas Resources Preservation Act of:

Westcoast Transmission Company Limited and Westcoast Transmission Company Ltd. (Alberta Incorporation)

Alberta Natural Gas Company, Alberta Natural Gas Grid, Ltd. and Northwest Natural Gas Company.

Western Pipe Lines.

Prairie Pipe Lines Limited and Prairie Transmission Lines Limited.

McColl-Frontenac Oil Company Limited and Union Oil Company of California.

Canadian Delhi Oil Ltd. and Trans-Canada Pipe Lines Limited.

Printed in Canada

Price $1.00

PROVINCE OF ALBERTA

THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD

TABLE OF CONTENTS

I Established Reserves of Natural Gas in the Province ---------- 6

II Trends in Exploration and the Growth of Reserves ---------- 6

III Present and Future Requirements of the Province ---------- 7

IV The Matter of Meeting the 1952-1981 Requirements of the Province ------ 7

V Gas Surplus to the Requirements of the Province ---------- 7

VI Validity of the Gas Resources Preservation Act ---------- 8

VII Disposition of the Applications of the following Applicants:
Alberta Natural Gas Company, Alberta Natural Gas Gas Grid, Ltd. and Northwest Natural Gas Company.
Western Pipe Lines.
Prairie Pipe Lines Limited and Prairie Transmission Lines Limited.
McColl-Frontenac Oil Company Limited and Union Oil Company of California.
Canadian Delhi Oil Ltd. and Trans-Canada Pipe Lines Limited ---------- 8

VIII Disposition of the Application of:
Westcoast Transmission Company Limited and Westcoast Transmission Company Ltd. (Alberta Incorporation) -------- 9

APPENDICES

A Established Reserves of Natural Gas in the Province
B Trends in Exploration and Growth of the Reserves
C Present and Future Requirements of the Province
D The Matter of Meeting the Requirements of the Province

LIST OF TABLES

	Page	Appendix
Table A-1—Established Reserves of Natural Gas in the Province of Alberta, December 31, 1951	17	A
Table A-2—Gas Strikes, 1951	21	A
Table B-1—Trends in Wildcat drilling and growth of Disposable Gas Reserves in the Province of Alberta	26	B
Table C-1—Estimate of Natural Gas Requirements	44	C
Table C-2—Allocation of Estimated Natural Gas Requirements between areas tributary to the Distributing Systems	45	C
Table D- 1—Illustrative Deliverability Schedule for the area tributary to the Canadian Western Natural Gas Company Limited System	57	D
Table D- 2—Illustrative Deliverability Schedule for the area tributary to the Northwestern Utilities Limited System	59	D
Table D- 3—Possible Sources of Supply for the Residual Requirements of the area tributary to Canadian Western Natural Gas Company Limited	50	D
Table D- 4—Possible Sources of Supply for the Residual Requirements of the area tributary to the Northwestern Utilities Limited System	51	D
Table D- 5—Presently known Reserves necessary to meet the estimated Residual Requirements of the Combined Canadian Western and Northwestern Utilities areas	51	D
Table D- 6—Fields connected or likely to be connected to small communities	52	D
Table D- 7—Remaining fields of Tables D-3 and D-4 excluding those of the Peace River area	53	D
Table D- 8—Illustrative Deliverability Schedule for the Residual Requirements of the Canadian Western area, the Northwestern Utilities area and the remainder of the Province	61	D
Table D- 9—Basic Deliverability Data for fields of Tables D-5 and D-7, excluding Pincher Creek	63	D
Table D-10—Illustrative Deliverability Schedule for the Peace River (Alberta) area and Dawson Creek, British Columbia	64	D
Table D-11—Basic Deliverability Data for fields of the Peace River area	65	D

LIST OF FIGURES

	Page	Appendix
Figure A-1—Map of Alberta showing Gas Strikes of 1951, by Census Division and Geological Age of Reservoir	22	A
Figure B-1—Trend in the growth of Disposable Reserves	28	B
Figure B-2—Trend in Disposable Reserve per Wildcat drilled	29	B
Figure B-3—Trend of the Ratio-Initial Disposable Reserves to Sales for the year	30	B
Figure C-1—Population Trends	40	C
Figure C-2—Trend in per capita Gas Consumption	41	C
Figure C-3—Trend in the use of Natural Gas	42	C
Figure C-4—Comparison of Mr. H. 'Harries and the Board's estimated future requirements for the Province of Alberta	43	C
Figure D-1—Relationship between Daily Delivery Capacity and remaining Disposable Reserves for the Composite Fields of Tables D-5, D-6 and D-7 excluding Pincher Creek	66	D
Figure D-2—Relationship for the Pincher Creek field between Daily Delivery Capacity and Remaining Disposable Reserves	67	D
Figure D-3—Relationship between Daily Delivery Capacity and Remaining Disposable Reserves for the Whitelaw, Tangent and Pouce Coupe fields	68	D

The Petroleum and Natural Gas Conservation Board, having publicly heard the applications under The Gas Resources Preservation Act of the aforelisted, having studied the evidence submitted at the public hearings, and having regard to the advice of its staff, to its own knowledge, and to its responsibilities under the Act, finds as follows:

I.—IN THE MATTER OF THE ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA

The Board estimates the established reserves of natural gas in the Province of Alberta as of December 31, 1951, to be 6.8 trillion cubic feet.

The present estimate compares with the Interim Report* estimate of just under 4.7 trillion cubic feet. The increase in estimate is due in part to new discoveries, partly to further development of previous discoveries and partly to new data and new interpretations concerning previous discoveries. Details of the new estimate and a comparison with the Interim Report estimate appear in Appendix A.

* Interim Report of The Petroleum and Natural Gas Conservation Board, January 20, 1951.

II.—IN THE MATTER OF THE TRENDS IN EXPLORATION AND THE GROWTH OF THE RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA

The Board believes that, with a continued incentive for exploration for oil and gas resulting in the drilling of some 400-500 wildcat wells per year, the Province of Alberta can safely anticipate the development of further established reserves of natural gas at an average rate of at least 1 trillion cubic feet per year for at least the next 8-10 years.

Statistics of the Province's record in discovering new gas reserves show that on the average, established reserves of over 400 billion cubic feet have resulted from the drilling of each 100 wildcat wells. The corresponding figure in the United States is some 300 billion cubic feet. Taking into consideration the area of favourable prospecting lands in the Province, together with the relatively small number of wildcat wells drilled, indications are that results in the range of these figures may be expected to continue at least for the drilling of a further 4000-5000 wildcat wells. Even the conservative expectation of 200 billion cubic feet for each future 100 wildcat wells suggests that a future growth in the established reserves of natural gas of at least 8-10 trillion cubic feet may be expected to accompany the drilling of the 4000-5000 wells. Appendix B presents statistical details of Alberta's record of wildcat wells drilled and new reserves of gas discovered, together with details of the Board's interpretation of these statistics.

III.—IN THE MATTER OF THE PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE OF ALBERTA FOR NATURAL GAS

The Board estimates the actual requirements of the Province of Alberta for natural gas for the 30 year period January 1, 1952, to December 31, 1981, to be 4.2 trillion cubic feet. This figure will have to be revised from time to time.

The present estimate compares with the Interim Report figure of just under 3.1 trillion cubic feet. Most recent evidence of the applicants and others was in general support of the 3.1 trillion cubic feet figure—although the Canadian Western Natural Gas and the Northwestern Utilities, Limited suggested "a safety factor of 25%." The Board has increased its estimate to 4.2 trillion cubic feet partly as a result of the accelerating population growth accurately reflected in the 1951 census figures and partly to provide for a greater degree of industrial development than contemplated at the time of the Interim Report. Full details of the revised estimate are presented in Appendix C.

IV.—IN THE MATTER OF MEETING THE 1952 - 1981 REQUIREMENTS OF THE PROVINCE OF ALBERTA FOR NATURAL GAS

The Board estimates that established reserves of natural gas of the order of 6.5 trillion cubic feet are necessary to meet the annual and peak day requirements of the Province from 1952 to 1981.

Detailed analyses of the ability of fields presently supplying Alberta requirements indicate that by about 1956 substantial further reserves not now connected will be required for the area tributary to the Canadian Western Natural Gas system and that by about 1963 large reserves not now connected will be required for the area tributary to the Northwestern Utilities system. Future discoveries of gas will greatly influence the manner in which these requirements may best be met. To insure that the requirements can be met has necessitated a study of how reserves now established could best be employed. The magnitude and location of presently established reserves, considered in conjunction with the magnitude and location of the requirements and the engineering and economic factors involved, indicates to the Board the present necessity of reserving for provincial use and other commitments all established reserves of the Province except 300 billion cubic feet in the general Peace River area. Detailed illustrative schedules showing the manner in which the presently established reserves might be used are presented in Appendix D. The schedules could be changed greatly in internal detail without significantly altering the result.

V.—IN THE MATTER OF NATURAL GAS SURPLUS TO THE 1952 - 1981 REQUIREMENTS OF THE PROVINCE OF ALBERTA

From the aggregate established reserves presently estimated at some 500 billion cubic feet in the Pouce Coupe, Tangent and Whitelaw fields, 300 billion cubic feet are estimated as surplus to the 1952-1981 requirements of the Province. No other gas is now estimated as surplus to the 1952-1981 requirements of the Province.

VI.—IN THE MATTER OF THE VALIDITY OF THE GAS RESOURCES PRESERVATION ACT

During the latter part of the 1951 Joint Hearing a submission was made by Alberta Inter-Field Gas Lines Limited contending or suggesting that The Gas Resources Preservation Act was ultra vires, particularly Section 9 thereof. The submission was accompanied by the written opinion of Professor Alex Smith of the University of Alberta, although no request was made to call Professor Smith as a witness.

The Board is of the opinion that this question is entirely beyond its jurisdiction.

VII.—IN THE MATTER OF THE PROPOSED SOURCES OF SUPPLY OF CERTAIN OF THE APPLICANTS AND OF THE DISPOSITION OF THEIR APPLICATIONS

The essential sources of supply proposed by the following applicants are fields which the Board cannot now declare, in whole or part, to be surplus to the requirements of the Province; therefore the Board must, and does, refuse their applications:

Alberta Natural Gas Company, Alberta Natural Gas Grid, Ltd. and Northwest Natural Gas Company.

Western Pipe Lines.

Prairie Pipe Lines Limited and Prairie Transmission Lines Limited.

McColl-Frontenac Oil Company Limited and Union Oil Company of California.

Canadian Delhi Oil Ltd. and Trans-Canada Pipe Lines Limited.

VIII IN THE MATTER OF THE AMENDED APPLICATION OF WESTCOAST TRANSMISSION COMPANY LIMITED, AND WESTCOAST TRANSMISSION COMPANY LTD. (ALBERTA INCORPORATION.) FOR PERMISSION TO CAUSE TO BE REMOVED AND TO REMOVE AN ANNUAL VOLUME OF 42 BILLION CUBIC FEET OF GAS FROM THE PROVINCE

The essential sources of supply proposed by the applicants are the fields of the Peace River area of which the Board estimated the reserves of Pouce Coupe, Whitelaw and Tangent at some 500 billion cubic feet. The applicants included other gas strikes in their estimate of 1200 billion cubic feet for the same area. A comparison of the two estimates follows:

Field	Disposable Gas Reserves—Billions of cubic feet	
	W.C.T.	Board, Dec. 31, 1952
Belloy	72.0	One well only—not estimated
Pouce Coupe	113.0	60.0
Whitelaw	337.0	316.0
Tangent	500.0	131.0
Spirit River (Dunvegan-Hamlin Creek)	125.0	One well only—not estimated*
Little Smoky	5.8	One well only—not estimated
Valley View	13.5	13.6
Normandville	25.8	3.5
Total	1192.1	524.1

* A follow-up well recently completed suggested field reserves of some 70 billion cubic feet.

The requirements of the Peace River area, including commitments to Dawson Creek, B.C., are estimated at some 117 billion cubic feet. Reserves of the order of 200 billion cubic feet are necessary to provide for these requirements and to meet their peak day demands leaving a surplus of 300 billion cubic feet.

The applicants propose to build a main transmission line from a point approximately three miles from the Alberta-British Columbia border almost due east of the Town of Rolla, B.C., through the interior of British Columbia to a point near the international boundary line about six miles from Sumas, Washington. At this point a branch line will continue to the City of Vancouver and the main line will go south to the United States.

The applicants further propose to construct a gathering and distribution system in Alberta to connect with the main transmission line near the Alberta-British Columbia border. The main line of the proposed gathering system follows a route nine miles straight south of the main transmission line intake, then travels east for ninety-one miles to the Normandville field with laterals to the Spirit River (Dunvegan - Hamlin Creek), Whitelaw, Bluesky, Belloy, Clairmont and Tangent gas fields with a forty-seven miles sales lateral to Grande Prairie. The proposed sales lateral will make gas available to the communities of Spirit River, Rycroft, Esher, Woking, Webster, Sexsmith, Clairmont and Grande Prairie.

The proposed gathering and distribution system in Alberta comprises 100 miles of main line and 111 miles of branch lines.

Mr. J. O. Patterson, President of the Chamber of Commerce of the Town of Grande Prairie made a submission to the Board in support of the applicants' application on the following grounds:

(a) That Grande Prairie is the largest community in Alberta without natural gas.

(b) That Grande Prairie and the communities in the Peace River area are at a further disadvantage as compared with communities in the rest of the Province, in that the cost of other fuels is probably the highest in the Province. He quoted coal at $14.75 per ton and fuel oil at 22c per gallon.

(c) That the Canadian Utilities Limited at Grande Prairie is anxious to obtain an adequate supply of gas in order to keep electricity at a minimum cost to the people of the Peace River territory.

(d) That the current exploration and drilling programme has brought an economic advantage to the area, particularly during the winter months when agricultural activity is more or less dormant. The people are anxious to see this prosperity continue and are fearful that if there is no market outlet for the gas that a substantial amount of such drilling and exploration will not continue.

Mr. Patterson went on to state:

" . . . Because of these and other factors, we hope that your Board in its deliberations can give favourable consideration to our case. To be perfectly frank, we realize that the market which can be supplied by the Town of Grande Prairie and other communities along the way is probably not sufficient to justify a pipeline direct from existing gas fields, but we understand that one of the applicants for export, the Westcoast Transmission Company, will have its gathering system passing approximately 45 miles from Grande Prairie and has undertaken before this Board to construct a line to our Town from such gathering system. We are therefore in the rather unique position that, as Alberta residents, we can only obtain our gas, as far as we can see, if export via the above company's line is authorized. This is also true of the various other communities in the Peace River area. Our understanding is that some 200 miles of pipeline in the Peace River area of Alberta are to be built by the Westcoast Company covering nearly all of the area and that the routes of such pipelines in following the main railroads and highways would bring nearly every populous centre and a great many farms within reach of gas supplies."

"It is our submission, therefore, that conditions, in so far as gas is concerned in the Peace River area, are so different from those in the rest of the Province that special consideration should be given to the needs of our area, and that the factors in so far as gas and possible export are concerned that might apply to the rest of the Province should not apply to the Peace River area."

The Board has considered the representations of the Grande Prairie Chamber of Commerce together with those of the applicants and recognized the fact, among others, that the Peace River area is remote from other settled areas in the Province and does not lend itself readily to an integrated province-wide gathering and distributing scheme. Accordingly, the Board is of the opinion that it would be to the advantage of the Peace River area, and without danger to the protection of other areas of the Province, to permit the applicants to remove gas from the Province subject to stringent conditions for the protection of the Province and the residents in the area.

Respectfully submitted,

I. N. McKinnon,
Chairman.

D. P. Goodall, P. Eng.,
Deputy Chairman.

G. W. Govier, P. Eng.,
Board Member.

Dated at Edmonton, Alberta,
this 29th day of March, 1952.

APPENDIX A

IN THE MATTER OF THE ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA

In its Interim Report of January, 1951, the Board published its findings as of that time with respect to Established Reserves of disposable gas. Those reserves were summarized as follows:

	Billion Cubic Feet
Local Use	382
General Use	4,057
Beyond Economic Reach	219
Total	4,658

During 1951 numerous new gas discoveries were made. Previous discoveries were, in many instances, developed beyond the discovery stage by the drilling of additional wells, and partially developed reserves have seen further development. New information has become available as to the reservoir characteristics of some of the previously discovered reserves through core analysis, electro and radio-activity logs and various other tests. As a consequence a great accumulation of new data was submitted to the Board during the hearings conducted in the latter part of 1951.

Canadian Delhi Oil Ltd. and Trans-Canada Pipe Lines Limited, applicants which had not been heard at the time of the preparation of the Interim Report, presented a new and independent estimate of the gas reserves of the Province through the consulting firm of DeGolyer and McNaughton. Dr. A. W. Nauss, acting for West Coast Transmission Company Limited, presented a revised estimate to bring his previous estimate of gas reserves up to date as of August, 1951, Messrs. R. H. King and M. B. Crockford of the Board's engineering and geological staffs submitted independent estimates for the Morinville area and for the reserve in the south-eastern part of the Province generally referred to as the Cessford area. No detailed estimate had been submitted for the Cessford area during the 1950 hearing. Estimates of the gas reserves of their holdings in various parts of the Province were submitted by the following companies:

The California Standard Company	Princess area
Canadian Gulf Oil Company	Pincher Creek field
Britalta Petroleums Limited	Medicine Hat field
Shell Oil Company of Canada	Jumping Pound field

Hudson's Bay Oil and Gas Company Limited, McColl-Frontenac Oil Company and Union Oil Company of California presented briefs on gas development in areas in which these companies had interests. Mr. R. E. Davis took the stand to present detailed data relative to wells drilled by Northwestern Utilities, Limited and on cross-examination presented further data with respect to his previous estimates of gas reserves.

The estimates of DeGolyer and McNaughton, submitted in great detail, were in most instances considerably higher than the January, 1951, findings of the Board published in the Interim Report. This firm followed a common custom of classifying gas reserves into three categories, "proven," "probable" and "possible," and then applying discounts for gas left in the reservoir at termination pressure and for gas lost on the surface by process shrinkage, plant and field use, etc., to arrive at an estimate of the amount of gas available for market.

The most recent estimates of disposable gas submitted by DeGolyer and McNaughton and by Dr. Nauss for the entire Province, are listed below for comparison with the Interim Report estimate of the Board:

DeGolyer and McNaughton estimate—8,644 billion cubic feet
Dr. Nauss revised estimate— 7,811 billion cubic feet

In its review of the new and revised estimates, the Board was not surprised to find wide differences of opinion as to the reserves of individual fields since estimates of partially developed re-

serves are contingent upon a number of judgment factors (for acreage, thickness, etc.) often differently assessed by competent persons. The Board has found the different estimators each to be generally consistent in his own judgment and assessment as reflected in his estimates of the various fields. This is indicated by the comparison of the different estimates for the same fields, one estimator being consistently higher than another or lower than a third. Often, apparent inconsistencies were found attributable to the fact that an estimator had not made an independent study of all the available data but had accepted certain judgment figures of others.

By questioning witnesses who submitted reserve estimates, the Board attempted to find some comparison between the various concepts of proven, probable and possible reserves and the Board's "established" reserves as defined in the Interim Report (pages 15 and 16). Some witnesses considered their combined estimate of proven and probable reserves to be equivalent to the Board's established reserves in the sense that their existence and estimated amount could be reasonably counted upon. Others considered that their estimates of proven reserves together with some fraction of the probable reserves might be equivalent to the Board's concept of established reserves.

The Board has not changed its opinion respecting the requirement for established reserves as expressed in the Interim Report as follows:

> "It considers that if the present and future needs of the Province are to be adequately protected, there should be a reasonable expectancy that such gas reserves are available from presently known discoveries and that the gas can be developed economically and made available for use when and as required."

With these points in mind the Board has considered all reserves from the viewpoint of whether or not, and to what extent, they could be considered as "established" in the sense that their existence and estimated amounts could reasonably be counted upon. In the opinion of the Board only such "established reserves," properly discounted for reservoir and surface loss, warrant consideration for the protection of the present and future requirements of the Province. In order to arrive at a current estimate of "established" reserves consistent with this concept, the Board analysed in detail all the data and estimates submitted during the 1951 hearings and compared them with previous submissions and with its Interim Report findings.

The Board's conclusions resulting from this study are summarized in Table A-1. This table lists individually all "Established Reserves of Disposable Gas" estimated by the Board at ten billion or more cubic feet and, in addition, some smaller reserves which are available for local use or are situated adjacent to larger reserves. The table also shows an estimated total for the small reserves of less than 10 billion cubic feet not itemized individually. Details as to the acreage, thickness, etc., as presented in the Interim Report are not listed in Table A-1, since in most instances the "Gas in Place" (column 3) represents the Board's judgment composite of several estimates.

Referring then to Table A-1:—

Column	Presents
1	Name of field or best known well or wells.
2	Geological formation or zone from which gas is obtained.
3	Estimated volume of gas in the reservoir December 31, 1952, expressed in billions of cubic feet at standard conditions (14.4 p.s.i.a. and 60°F).
4	Discount applicable to "Gas in Place" (column 3) to account for the gas left in the reservoir at abandonment.
5	Discount applicable, after that for the reservoir loss, to account for surface loss. This factor includes (where applicable) allowance for gas flared, operational loss, field and/or plant fuel, and processing shrinkage attending the removal of carbon dioxide, hydrogen sulphide, propane and butanes plus.
6	Established reserves; reserves of disposable gas which in the opinion of the Board may be reasonably counted upon. The reserves are expressed in billions of cubic feet at standard conditions and are based upon the figures of columns 3, 4 and 5.
7	Comments of specific application to individual fields.

Summarizing the present findings of the Board with respect to Established Reserves of Disposable Gas, the Provincial total is 6.8 trillion cubic feet. This total includes all gas previously classified as "available for general use" or "local use" or considered "beyond economic reach." The classification is reflected by the comments under column 7.

The increase from the Interim Report figure of some 4.6 trillion cubic feet is due partly to new discoveries, partly to further developments of previous discoveries, and partly to new data and new interpretations related to incompletely developed reserves.

Comments With Regard to Certain Fields

In its Interim Report the Board expressed the opinion that there were specific possibilities, with further development, for an increase in the established reserves of Jumping Pound and Pincher Creek. While both of these fields have seen further development during 1951, the estimate for Jumping Pound has been reduced as the result of the additional information obtained whereas the Pincher Creek estimate has been increased substantially. The Board has revised both of these estimates chiefly as a result of new core data.

Jumping Pound

Prior to 1951 little was known regarding the porosity of the reservoir in Jumping Pound and engineers used the porosity of Turner Valley as a basis for their estimate. Subsequent analysis of cores from this field by the Shell Oil Company has indicated a lower porosity. The acreage estimate has also been reduced slightly and, with other minor adjustments to account for production to date and surface losses based on actual performance, the Board has reduced its Interim Report estimate of 540 billion cubic feet of disposable gas by 165 billion cubic feet to 375 billion cubic feet.

Pincher Creek

After a complete analysis of the cores from a recently completed well and a reassessment of the results of previous core analyses, Canadian Gulf Oil Company submitted a revised net porosity estimate which was considerably higher than their previous figure. Unfortunately Canadian Gulf did not have its core data prepared in time for the public hearings but full data were made available to the Board's engineering staff after the hearings closed. The revised estimate of the Board's engineers, using Canadian Gulf's up to date core data, is 1,680 billion cubic feet of disposable gas—an increase of 510 billion cubic feet over the Interim Report estimate of 1170 billion cubic feet. The Board concurs in this revised estimate.

Cessford

The Cessford area, situated in the south-eastern part of the Province, is a new reserve which saw a considerable amount of development during 1951. Wells which have encountered gas are dispersed over a large area and the outlines of individual pools are still in doubt. In various parts of the area gas occurs in the Viking sand, the Basal Colorado sand and in the Basal sands of the Lower Cretaceous. Geological conditions appear similar to that of the Princess-Patricia area which lies adjacent to Cessford south of the Red Deer River. The Board considers that caution should be exercised in estimating the areal extent of these reserves based on the relatively small number of wells drilled.

Medicine Hat

This field has been extended some miles eastward from the border of the field as known when the 1950 estimates were submitted to the Board. Prospect wells, widely spaced throughout this extension, have demonstrated that gas migration to the area of older development is very slow since what appears to be virgin reservoir pressure was found in wells only a few miles east of the old field. For these reasons the Interim Report pressure decline estimate of the Medicine Hat reserves is now believed too low. In its reassessment of this reserve the Board has considered both revised pressure decline estimates and new data as to areal extent, porosity, etc. The Board's present estimate of 513 billion cubic feet is some 60 per cent higher than the Interim Report figure.

Leduc-Woodbend

Although little factual information has been obtained on the occurrences of gas in the Lower Cretaceous from wells drilled during 1951, evidence was submitted during the hearings in support of

gas occurrences over a fairly extensive area. This opinion was based on a study of electrologs of oil wells and supported by drill stem tests on a relatively small proportion of the wells in the field. It is considered that the cost of development of this reserve will be low since it should be possible to perforate the casing at the gas horizon in oil wells after the oil production has become uneconomical. The Lower Cretaceous gas then can be produced through the old wells and transported through the pipe lines previously installed for gathering the gas from the Devonian oil reservoirs. Under these circumstances the gas from the Lower Cretaceous sands will, in a large part, be deferred until most of the oil has been produced. Although the economics of processing this gas through a plant for the extraction of liquid hydrocarbons is doubtful and the mechanics of producing and gathering the gas is dependent on so many factors far distant in the future, the Board feels that a revision in the Interim Report estimate of 47 billion cubic feet to130 billion cubic feet of disposable gas is justified.

No estimate was submitted to the Board for the gas cap gas in the D-2 zone of the Leduc-Woodbend field. Since development has demonstrated the existence of localized gas cap gas, the Board has introduced an estimate of 11 billion cubic feet of disposable gas cap gas for the Leduc D-2 zone.

The estimate of disposable gas from solution in the D-2 oil reservoir has been increased from 66 billion cubic feet to 99 billion cubic feet. This increase was caused largely by extensions of the field during 1951.

The estimate of disposable gas for the D-3 zone plus production to date remains essentially the same as that of the Interim Report.

Morinville, Legal, Waybrook, Manawan Lake and Calahoo

Twenty-three wells were drilled in this composite area during 1951. Most of these were in the vicinity of Morinville and Legal and were drilled expressly for gas in an attempt to establish additional reserves for the increased requirements of the Edmonton area. Out of the twenty-three wells drilled, twelve were completed as gas wells, seven were abandoned as dry holes and four encountered oil instead of the anticipated gas. The area appears to be developing into several relatively small and irregularly shaped fields. The distribution of gas bearing sands appears erratic and the Board anticipates that a fairly large percentage of non-productive wells will be drilled in any attempt to develop a major gas reserve in this general area.

Tangent

This gas reserve was discovered while drilling 'Hudson's Bay Union North Tangent No. 1 well during the early part of 1951. The discovery well is situated in section 34 of township 80, range 24, west of the fifth meridian, about 22 miles south-west of the town of Peace River. Some gas occurs in the Peace River sand but the main productive horizons are in the Gething series of the Lower Cretaceous and in the Triassic.

Since this discovery well, six additional wells have been drilled on a relatively wide spacing pattern in an attempt to outline the areal extent of the productive sands. By the end of the year four wells had been completed as potential gas producers and from evidence submitted, the Board now estimates that a total reserve of 131 billion cubic feet of disposable gas has been established.

Turner Valley

During the 1951 hearings a new estimate of the gas reserves of Turner Valley was submitted by engineers of DeGolyer and McNaughton. This estimate was considerably higher than the 300 billion cubic feet estimate of disposable reserves for this field as published in the Interim Report. After study of the details of the new estimate and further study of the estimate submitted by Mr. R. E. Davis the Board has revised its estimate of the combined reserves of disposable gas in Turner Valley from the Interim Report figure of 300 billion cubic feet to 346 billion cubic feet.

Viking-Kinsella

During the 1951 hearings new data and interpretations concerning the Viking-Kinsella field were submitted and various opinions were expressed by witnesses relating to the contribution, to the

reserves of disposable gas, that might be expected from the thin sands fringing the developed portion of this field or the portion likely to be developed. Evidence was submitted showing that some gas migration from the outer boundaries of the older portion of the field has already taken place. The differences in opinion expressed by witnesses indicate however, that the amount of migration which can be expected during the economic life of the field is a subject of some conjecture.

After considering all material submitted, the Board has revised the estimate of the disposable gas reserves of the Viking-Kinsella field from 582 to 676 billion cubic feet.

Whitelaw

The Interim Report estimate of 108 billion cubic feet of disposable gas reserves for this area was based on the findings of two wells. During 1951, seven additional wells were drilled in an attempt to outline the productive area. Of these only three found sufficient gas to warrant their completion as gas wells. Although results of drilling have been disappointing on the whole, a considerable amount of additional acreage over that previously assigned to the two wells has been found to be productive of gas. From the additional information obtained, the estimate of disposable gas from this area has been raised from 108 to 286 billion cubic feet.

Small Reserves and New Discoveries

As stated previously, Table A-1 lists in detail only those gas reserves now estimated by the Board as containing 10 or more billion cubic feet of disposable gas. Exceptions to this are cases where a reserve of less than 10 billion cubic feet is combined in a field area with other reserves aggregating more than 10 billion cubic feet, or where the reserve is in close proximity to a large reserve or where the reserve is being used or could reasonably be expected to be used to supply a local market.

There are many other small reserves (as estimated in the light of present development) widely dispersed throughout the Province. Some of these have not been developed beyond the initial discovery well and reserve estimates of many others have been based on several wells so widely spaced that there is some doubt at the present time if there is reservoir communication between wells. Many of these reserves are in sand bodies of the Lower Cretaceous which, generally, are of irregular shape and most difficult to outline by drilling.

Past experience in both the central and southern parts of the Province has demonstrated the risk involved in attempts to develop marketable reserves from such sands. One only has to consider the ratio of dry holes to productive wells resulting from the development to date of Lower Cretaceous sands at Elk Point, Bonnyville, St. Paul, Vermilion, Morinville, Princess, and other similar areas to realize that, had 640 acres spacing been adhered to in all instances, the dry hole ratio could have been at least one for every producer. In addition to the gas fields mentioned there are a number of fields in the Province which have been developed for oil in the Lower Cretaceous or other lower horizons. In these fields the close spacing of wells for oil production has afforded a good opportunity of studying the extent, continuity, and productivity of the Lower Cretaceous gas bearing sands. Moreover the discovery wells at Leduc, Redwater and Acheson each encountered a substantial flow of gas in the Lower Cretaceous but a study of electrologs of subsequent wells show that development of the gas reserves in each of these fields on a 640 acre or greater spacing pattern would have been most difficult and costly. Such observations confirm the need for caution in the estimation of undeveloped Lower Cretaceous gas reserves.

Less is known regarding the distribution and continuity of the sand of the Lower Cretaceous in the northern part of the Province. Since the sediments of the Lower Cretaceous in that area are predominantly of marine deposition, it is hoped that the distribution of the sand may be more uniform and that some fairly extensive gas pools may be developed.

Although Table A-1 omits individual estimates of many small reserves, a total of the estimates of some 30 small pools having individual reserves of less than 10 billion cubic feet has been included. In addition to these, over 100 "potential" gas pools were referred to in technical submissions to the Board. Owing to the lack of factual data however, estimates of reserves were not presented for these "potential" pools.

During 1951 numerous discoveries of gas were made while drilling exploratory wells for oil. Some of these strikes have seen further development but most have not been explored beyond the initial discovery. Table A-2 is presented to show the distribution of 1951 gas discoveries by areas (Dominion census divisions) and by the major geological ages of rocks. In preparing this table only gas strikes which, on test, indicated a flow at a rate of one million or more cubic feet per day were considered. The statistics of the table are also recorded on a map of the Province (Figure A-1). A review of these data shows that the greatest concentration of gas discoveries has occurred in the central part of the Province, where extensive exploration for oil has been carried out during the year. It will be observed that the major proportion of the 1951 gas discoveries were in the Lower Cretaceous—with the Upper Cretaceous running a close second.

Although the Upper-Lower Cretaceous contact is now generally conceded by geologists to occur above the sandy sediments containing the Basal Colorado, Bow Island, Viking, Pelican and Peace River sands referred to in Table A-1 and Table A-2, these reservoirs are classified herein as Upper Cretaceous in order to keep them on a comparable basis with the Interim Report classification.

During 1951 also, several promising gas discoveries were made in the Paleozoic limestones. Two of these strikes received special mention by engineers during the hearings as potential reserves for the area tributary to the Canadian Western Natural Gas Company Limited system. One of these discoveries was made by the drilling of the Shell Mackidd No. 1 well situated about 16 miles southeast of Calgary. The other strike was made by Bailey Olds No. 1 well in the Neapolis district about 38 miles north of Calgary.

At the close of the year another discovery of great interest was made by the drilling of Texaco Bonnie Glen No. A-1 well situated in the central part of the Province, about nine miles south of the Leduc field. There, the gas forms a thick cap over crude oil and its production undoubtedly will be deferred in the interests of optimum oil recovery.

Table A-1

The Petroleum and Natural Gas Conservation Board

ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA, DECEMBER 31, 1951.

1	2	3	4	5	6	7
FIELD	ZONE	Estimated Original Gas In Place billions of cubic feet	Discount for Reservoir Loss per cent	Discount for Surface Loss, Etc. per cent	Disposable Gas December 31, 1951 billions of cubic feet	REMARKS
Acheson	Viking	10.0	20	5	7.6	Production may be deferred until oil produced from limestone reservoir.
	Blairmore	15	10	5	13	Production may be deferred until oil produced from limestone reservoir.
Athabasca	Blairmore	10.0	20	5	7.6	Supplies local utility.
	D-1	2.0	20	5	1.5	Can provide further supply for local use.
Battle-View Vermilion	Lower Cretaceous	15	15	10	12	Supplies local utility.
Black Butte Pinhorn	Bow Island	2.5	20	5	1.9	Gas supply for Canadian-Montana Gas Company Limited.
	Ribbon	25	15	5	20	
	Ellis	9.0	20	5	6.8	
	Madison	8.0	10	20(1)	5.8	(1) Surface loss higher than normal due to need for processing to remove hydrogen sulphide.
Bon Accord	Viking	10.0	15	5	8.1	Same as Interim Report for gas in place, 5% surface loss. Might supply gas for local use.
Bonnyville	Lower Cretaceous	3.9	20	5	3.0	Supplies local utility.
Bow Island	Bow Island	19	10	5	16	Calculation by pressure-decline method. Used as storage field for C.W.N.G. System. Reservoir loss revised from Interim Report.
Boyle Mustang-Amisk Lake	Upper Grand Rapids	16.0	10	5	14	
	Middle Grand Rapids	4.0	10	5	3.4	
	Lower Grand Rapids	10.4	10	5	8.9	
	McMurray	4.2	15	5	3.4	
	Nisku	8.0	10	5	6.8	
Brooks-Tilley	Milk River	25	20	5	19	Supplies two local utilities and shallow gas wells for farm use.
Brooks N.E.	Blairmore	6.0	20	5	4.6	Some gas used for local utility.
Campbell	Blairmore Gas Cap	10.3	10	18(1)	7.6	(1) 13% shrinkage, 5% loss. May be deferred to assist in oil production.
	Blairmore Gas Cap	8.2	10	18(1)	6.1	(1) 13% shrinkage, 5% loss. May be deferred to assist in oil production.
	Blairmore solution	2.4				Economics of gathering presently considered doubtful.
Castor	Viking	21	10	5	18	May be required for local utility use.
	Lower Cretaceous	19	10	5	16	May be required for local utility use.

Table A-1—continued

1	2	3	4	5	6	7
FIELD	ZONE	Estimated Original Gas In Place billions of cubic feet	Discount for Reservoir Loss per cent	Discount for Surface Loss, Etc. per cent	Disposable Gas December 31, 1951 billions of cubic feet	REMARKS
Cessford	Viking	56	15	5	45	Appears to consist of several reservoirs.
	Basal Colorado	340	15	5	275	Appears to consist of several reservoirs.
	Sunburst	140	10	5	120	Appears to consist of several reservoirs.
Countess	Bow Island	70	10	5	60	
Dunmore	Bow Island	5.0	20	5	3.8	Interim Report estimate with less surface loss.
	Ellis	20	20	5	15	Interim Report estimate with less surface loss.
Elk Point	Blairmore	6.6	20	5	5.0	Supplies local utility and salt plant.
Excelsior	Viking	8.7	15	5	7.0	May be deferred until oil produced from Devonian reservoir.
	Blairmore	31	10	5	27	May be deferred until oil produced from Devonian reservoir.
Foremost	Bow Island	34.5(1) 29.0(2)	20(1) 24(2)	5	21	(1) Original. (2) Less 5.5 produced to Dec. 31/51 (Pressure decline calculation).
Golden Spike	Viking	3.8	20	5	2.9	May be deferred until oil produced from Devonian reservoir.
	Blairmore	30	10	5	26	May be deferred until oil produced from Devonian reservoir.
	D-1	8.6	10	5	7.4	May be deferred until oil produced from Devonian reservoir.
	D-3	78				Economics of gathering and processing presently considered doubtful.
Hanna	Viking	3.8	15	5	3.0	May be required for local use.
	Blairmore	5.6	15	5	4.5	May be required for local use.
	Madison	10.4	15	5	8.4	May be required for local use.
Joseph Lake	Viking Gas Cap	6.3				Expected all gas to be produced with oil, economics of gathering presently considered doubtful.
	Viking solution	7.4				Expected all gas to be produced with oil, economics of gathering presently considered doubtful.
Jumping Pound	Rundle	527(1) 522(2)	10(1) 10(2)	20	375	(1) Original. (2) Less 5.0 produced to Dec. 31/51.
Lac La Biche	Pelican	4.0	15	5	3.2	
	Blairmore	11.0	10	5	9.4	
Leduc-Woodbend	Lower Cretaceous	160	10	10	130	Deferred until oil produced from Devonian reservoir.
	D-2 solution	187(1) 180(2)	20.8(1) 21.7(2)	30(3)	99	(1) Original. (2) Less 6.8 produced to Dec. 31/51. (3) Assume 80% gathered, 25% shrinkage and use adjusted by 1.16 factor to convert to 1000 B.T.U. basis.

	D-2 Gas Cap	15	10	18	11	Expect production to be deferred until most of the oil is produced.
	D-3 solution	270(1) 255(2)	15.0(1) 15.9(2)	26(3)	159	(1) Original. (2) Less 14.8 produced to Dec. 31/51. (3) Assume 85% gathered, 25% shrinkage and use adjusted by 1.16 factor to convert to 1000 B.T.U. basis.
	D-3 Gas Cap	650(1) 625(2)	10.0(1) 10.4(2)	18	459	(1) Original. (2) Less estimated 25 produced from Atlantic No. 3. Expect production to be deferred until most of the oil is produced.
Lloydminster	Colony	5.8	20(1)	5	4.4	(1) High because field is partly depleted./Supplies local utility.
	Sparky	0.9	30(1)	5	0.6	(1) High because field is partly depleted./Supplies local utility.
Majeau Lake	Viking	3.1	20	5	2.4	
	Glauconitic	5.9	15	5	4.8	
	Mississippian	3.0	10	15(1)	2.3	(1) Wet, must be processed.
Manyberries	Upper Bow Island	8.0	20	5	6.1	
	Lower Bow Island	73	15	5	59	
Medicine Hat	Medicine Hat Sand	939(1) 759(2)	20(1) 24.8(2)	10	513	(1) Original. (2) Less estimated production at 180.
(Morinville, Legal, Waybrook, Manawan Lake, Calahoo)	Basal Cretaceous	185	10	10	150	Consists of a number of fields partially developed for industrial market.
	Viking	24	15	5	19	Consists of a number of fields partially developed for industrial market.
Oyen	Viking	22	15	5	18	
Pelican	McMurray	16	15	5	13	Interim Report estimate with less surface loss.
Pendant d'Oreille and California Standard Area	Bow Island	343	20	5	261	Supplies gas to Canadian-Montana Gas Co. Ltd.
Picardville	Viking	29	15	5	23	Supplies local utility.
Pincher Creek	Rundle	2500	16(1)	20(2)	1680	(1) Includes 7% loss at separator. (2) Plant use, shrinkage and loss. Contains H_2S, wet.
Princess, Patricia, Rainy Hills, Steveville and Toronto	Basal Colorado	45	15	5	36	
	Sunburst	77	10	10(1)	62	(1) Surface loss high because of Nitrogen and resulting low B.T.U. value.
	Jefferson	39	10	20(2)	28	(2) Surface loss high because of 13% Nitrogen and resulting low B.T.U. value.
Pouce Coupe	Peace River	75	15	5	60	Total produced to Dec. 31/51 about 0.45. /Supplies Dawson Creek, B.C.
Provost	Viking	110	20	5	84	Interim Report with less surface loss.

Table A-1—continued

1	2	3	4	4	6	7
FIELD	ZONE	Estimated Original Gas In Place billions of cubic feet	Discount for Reservoir Loss per cent	Discount for Surface Loss, Etc. per cent	Disposable Gas December 31, 1951 billions of cubic feet	REMARKS
Redwater	D-3	240				Economics of gathering and processing presently considered doubtful.
	Viking	2.6	20	5	2.0	Supplies local utility.
Sibbald	Viking	17	20	5	13	
Smith Coulee	Bow Island	22	20	5	17	Interim Report, with less surface loss. Supplies gas to Canadian-Montana Gas Co. Ltd.
Stettler (includes Leahurst)	Lower Cretaceous	15	15	5	12	May provide supply for local utility.
	D-2 solution	6				Economics of gathering and processing presently considered doubtful.
	D-3 solution	1.6				Economics of gathering and processing presently considered doubtful.
St. Paul	Blairmore	3.9	20	5	3.0	Interim Report estimate. Supplies local utility.
Sturgeon (Qui Barre)	Basal Blairmore	27	10	5	23	
Suffield	Milk River	25	20	5	19	Supplies local utility.
Tangent	Peace River	18	15	5	15	
	Gething	56	20	5	43	
	Triassic	85	10	5	73	
Turner Valley	Rundle				346	
Valleyview	Peace River	6.1	20	5	4.6	
	Gathing	11.8	20	5	9.0	
Viking-Kinsella	Viking	1100(1) 932(2)	20(1) 23.6(2)	5	676	(1) Original. (2) Less estimated 168 produced to Dec. 31/51.
Whitelaw	Peace River	28	20	5	21	
	Gething	66	10	5	56	
	Triassic	280	10	5	239	
Wizard Lake	Viking	2.7	10	5	2.3	
	Lower Cretaceous	4.3	10	5	3.7	
	D-3 solution				22.0	Tentative estimate based on oil reserve calculation.
Total of other reserves less than 10 billion cubic feet not listed above.					116	
				Total	6829.9	

SAY 6.8 TRILLION CUBIC FEET

GENERAL NOTES:

(1) Unless otherwise noted reservoir loss is calculated as 10% of original gas in place except in the particular cases where the following losses pertain:
Sand thickness 10-15 ft. Reservoir loss=15%.
Sand thickness 5-10 ft. Reservoir loss=20%.
Sand thickness 0- 5 ft. Reservoir loss=25%.

(2) Surface loss is taken as 5% for all dry gas, and varies for wet gas depending upon its composition.

Table A-2
GAS STRIKES, 1951

No.	CENSUS DIVISION 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	Total
*Upper Cretaceous	1		5		8		1	5		2	7			7	2	4		42
Lower Cretaceous			1		5	1	2	5		7	19		2	9	1	7		59
Jurassic				1														1
Triassic																1		1
Paleozoic				1		1		5		1	2	1		2		2		15
Total	1		6	2	13	2	3	15		10	28	1	2	18	3	14		
																		Provincial Total—118

* Basal Colorado, Bow Island, Viking, Pelican and Peace River sands included.

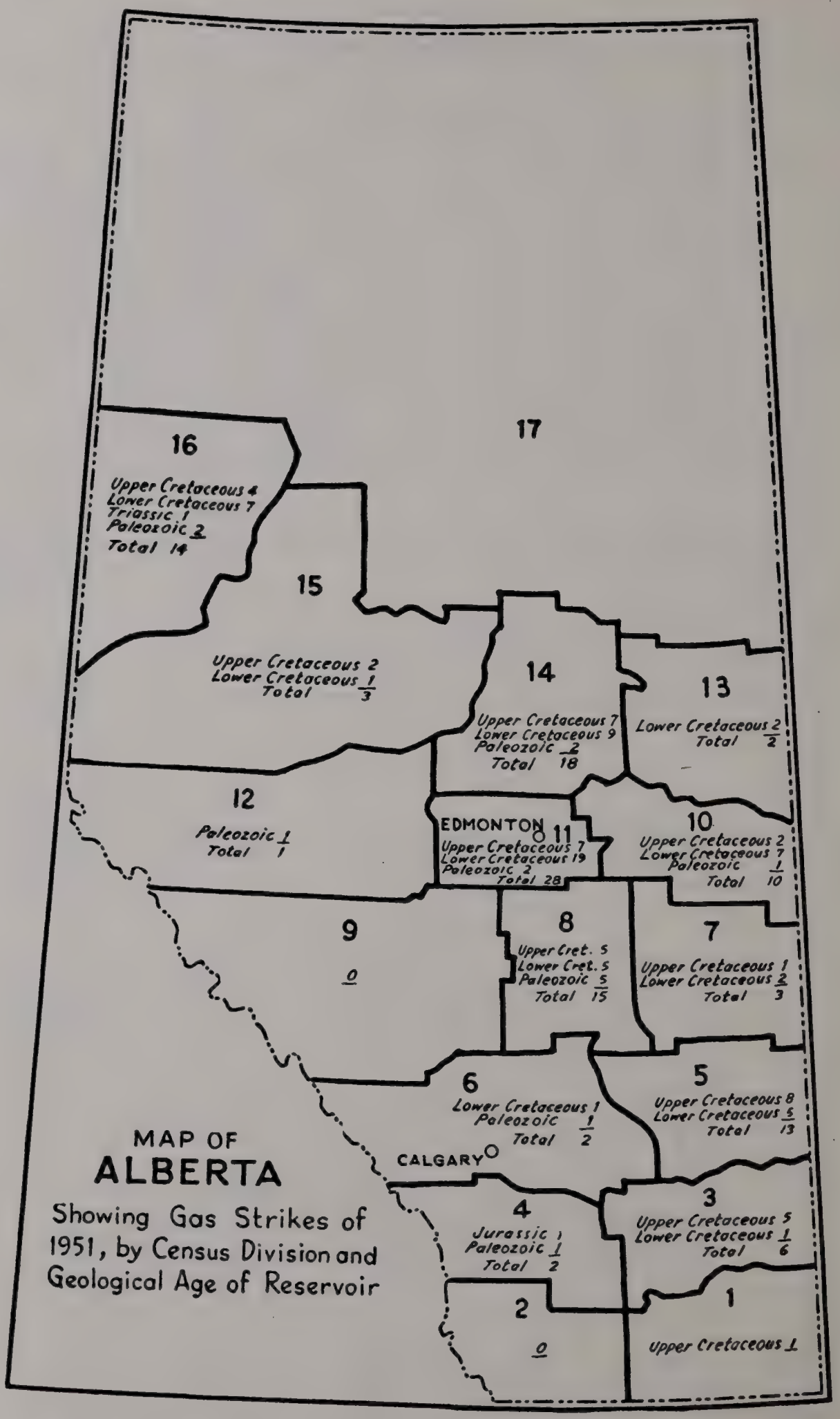

17
16
Upper Cretaceous 4
Lower Cretaceous 7
Triassic 1
Paleozoic 2
Total 14
15
Upper Cretaceous 2
Lower Cretaceous 1/3
Total
14
Upper Cretaceous 7
Lower Cretaceous 9
Paleozoic 2
Total 18
13
Lower Cretaceous 2/2
Total
12
Paleozoic 1/1
Total
EDMONTON
11
Upper Cretaceous 7
Lower Cretaceous 19
Paleozoic 2
Total 28
10
Upper Cretaceous 2
Lower Cretaceous 7
Paleozoic 1/10
Total
9
0
8
Upper Cret. 5
Lower Cret. 5
Paleozoic 5/15
Total
7
Upper Cretaceous 1
Lower Cretaceous 2/3
Total
6
Lower Cretaceous 1
Paleozoic 1/2
Total
5
Upper Cretaceous 8
Lower Cretaceous 5/13
Total
MAP OF
ALBERTA
Showing Gas Strikes of
1951, by Census Division and
Geological Age of Reservoir
CALGARY
4
Jurassic 1
Paleozoic 1/2
Total
3
Upper Cretaceous 5
Lower Cretaceous 1/6
Total
2
0
1
Upper Cretaceous 1

Figure A-1

APPENDIX B

IN THE MATTER OF THE TRENDS IN EXPLORATION AND GROWTH OF THE RESERVES

In its Interim Report the Board made reference to the unanimous opinion of geologists who had appeared before it to the effect that "vast reserves of gas can be discovered with an extensive drilling program." Again, in its Interim Report conclusions the Board stated that it

". . . . . believes it is in the best interests of the Province to encourage gas development and that if as a result of more intensive exploration and the establishment of further gas reserves, a successful trend is indicated, the Board would be prepared to consider recommending the granting of an export permit based upon a lesser degree of provincial protection." This is believed consistent with the viewpoint expressed by the Dinning Commission that the future may be judged from three viewpoints, namely:

(1) "Past performance regarding additions to known reserves and the industry's record in meeting requirements."

(2) "Analysis of statistical data bearing on the rate of discovery of new gas and the results of drilling operations, including wildcats drilled and the number of dry holes."

(3) "Consideration of the areas believed to be favorable for the finding of oil and gas and of the extent to which such areas have already been explored."

Evidence of Dr. A. D. Brokaw indicated that the reserve estimates of Dr. Hume and Dr. Nauss both reflected a growth in reserves of over one trillion cubic feet per year during the period mid 1948 to mid 1949; this representing some 18 times the annual production. Mr. Trostel drew the attention of the Board to rate of growth of the "initially recoverable gas reserves" and the acceleration since about 1946. He also pointed out the fact that the total drilling effort in the Province's some 156,000 square miles of prospective territory was the equivalent of only one well per 95 square miles. Impressed with these statements and with similar ones from other witnesses, the Board has given further study to the matter of trends in drilling and growth of reserves.

Statistical data dealing with wildcat wells drilled and gas reserves discovered over the period 1930 to December 31st, 1951, are presented in Table B-1. The reserve figures in Column 5 represent the estimated remaining reserves of disposable gas as presented in Table A-1 of the previous section. Column 6 reflects the estimated cumulative sales from the fields, from their discovery dates to December 31, 1951, and Column 7 indicates the estimated disposable gas reserves at date of discovery. Cumulative figures for the disposable gas reserves at date of discovery for the entire Province appear in Column 8. These data are presented graphically in Figures B-1, B-2 and B-3 from which the trends may be examined. Figure B-1 is a plot showing the relationship which has existed between cumulative initial reserves of disposable gas (Column 8, Table B-1) and cumulative number of wildcat wells drilled (Column 3, Table B-1).

It will be noted that the data are described by a light line drawn through the points. In considering the trend of the relationship it is believed that a few more years' development will show the reserve additions of 1949, 1950 and 1951 to be somewhat greater than now estimated and that weight should be given to this probability in order that the reserve discoveries for all years will be on a comparable basis, i.e., estimates made after the benefit of three or four years of development. This procedure is that discussed and recommended in "Petroleumn Conservation", a recent publication of the American Institute of Mining and Metallurgical Engineers. With this in mind, the solid line AA would seem to be a conservative representation of the data. It is of interest to observe that the inclination of this line with respect to the horizontal axis is less than the 45 degree angle which would represent a gain in reserves directly proportional to the number of wildcats drilled.

This general trend line cannot by itself be employed to estimate future reserves, because its extension is contingent upon (a) the existence of much gas yet undiscovered and (b) the continuation of an active exploration program. Some notion of the propriety of extending the trend line, even assuming the exploratory effort required, is gained from a consideration of the amount of

exploratory effort so far expended compared to the area of prospective gas lands. In the Province of Alberta, according to the Board Geologist, there are some 125,000 square miles of potential plains land and some 12,000 square miles of potential foothills land, a total of over 135,000 square miles. A total of 5,163 wells, of which 1,650 were wildcats, had been drilled in this vast area at the close of 1951. This represents an average drilling density of one well to 26 potential square miles, or considering wildcats alone, one well to every 82 potential square miles.

Assume that gas discoveries will continue, although at a decreasing rate per unit exploratory effort until, say, one wildcat has been drilled for each 10 square miles. This means that some 13,000 wildcats might be drilled before the returns become negligible. Reducing the results per unit effort at a rapid fall-off to zero at 13,000 wildcats, permits the extension of the trend line AA as indicated by its dotted portion. While this extension does not necessarily indicate the ultimate initial reserves, it does suggest that the trend line could be taken as reasonable at least part way to the "saturation point", say as far as the drilling of some 6,000 wildcats—or some 4,500 further wildcats. This would correspond to an increase in initial reserves of disposable gas of some 8 to 9 trillion cubic feet. When and whether such wells will be drilled depends upon the continuation of an incentive. If they should be drilled at an average of 500 per year one might reasonably expect, for some nine years, gains in reserves averaging approximately one trillion cubic feet per year—the same figure suggested by Dr. Brokaw.

Another interpretive approach is that of Figure B-2 which shows the trend of the initial reserves of disposable gas discovered each year per wildcat well drilled in the same year. The variations of from 0 to 16.2 billion cubic feet per wildcat makes the determination of the trend difficult but the over-all average in Alberta to date is 4.5 billion cubic feet per wildcat drilled as indicated in the figure. The average for the years 1941-1951 is indicated as 3.7 billion cubic feet per wildcat. A conservative anticipated average for the years 1941-1951 having in mind further development of discoveries in 1949, 1950 and 1951 as previously discussed, is 4.2 billion cubic feet per wildcat drilled. It is felt that 4.0 billion cubic feet per wildcat drilled is a realistic interpretation of what can be expected per wildcat drilled at the present time.

This may be compared with a 1941-1949 inclusive average for the United States of some 120 trillion cubic feet of marketable gas with 42,000 odd wildcat wells or approximately 2.9 billion cubic feet per wildcat drilled. ("Petroleum Conservation", ibid). Even assuming that the average Alberta figure of four billion cubic feet per wildcat should decrease to two billion cubic feet per wildcat for a further 4,500 wildcats, a gain in initial reserves of disposable gas of some nine trillion cubic feet is indicated. Again, at an exploration rate of 500 wildcats per year, new reserves of one trillion cubic feet per year might reasonably be expected for some years.

Figure B-3 has been constructed to show the past trend in the ratio of remaining reserves of disposable gas to annual requirements and to indicate the future possibilities. It will be noted that the remaining reserve-annual requirement ratio has fallen from some 166 in 1932 to some 127 in 1951. These values compare with December 31, 1949, values of 33 for Texas, 32 for Louisiana, 44 for Kansas, 19 for Oklahoma and 29 for the United States as a whole. (ibid) It is seen that Alberta's present ratio is indeed a favorable one.

The extension of the ratio trend into future years is extremely difficult, involving as it does both the unknown future reserves and estimates of future requirements of the Province. It is instructive, however, to consider what would be the ratio trend, in the absence of export, in the following two cases:

(a) Assuming that the contemplated future requirements of the Province (details in Appendix C following) are realized, and assuming that the contemplated reserve additions of line AA extended are realized up to the drilling of some further 4,500 wildcats,

and

(b) Assuming that the contemplated future requirements of the Province are realized, and assuming that there are no future reserve additions.

The dotted extensions of Figure B-3 marked BB and CC refer respectively to the above-

assumed conditions. The extension BB shows that with the contemplated reserve additions and future requirements the ratio might be expected to average about 95 (or nearly three times the present Texas ratio) for the next 30 years. On the other hand, the extension CC indicates that with no reserve additions but assuming the contemplated future requirements, the ratio would decline to a low of about 15 after 30 years. The Board, however, cannot accept the extension CC based upon no reserve additions as realistic in any sense. It is the Board's view that the extension BB is conservative and realistic indicating, for the condition of no export, a diminishing ratio from the present figure near 127 to a figure near 60 after 30 years. This suggests that, without export but even after 30 years, the reserve-requirement position would be nearly two times stronger than that now prevailing in the major gas-producing States.

Table B-1

The Petroleum and Natural Gas Conservation Board

TRENDS IN WILDCAT DRILLING AND GROWTH OF DISPOSABLE GAS RESERVES IN THE PROVINCE OF ALBERTA

1	2	3	4	5	6	7	8
Year	Wildcat Wells Per Year	Wildcat Wells Cumulative	Name of Field	Disposable Gas Reserves as of December 31, 1951, billions of cubic ft.	Sales to December 31, 1951, billions of cubic ft.	Disposable Gas Reserves at date of discovery, billions of cubic ft.	Cumulative Disposable Gas Reserves at date of discovery, billions of cubic ft.
Prior to 1930		172	Medicine Hat, Bow Island, Brooks, Tilley, Castor, Viking-Kinsella, Turner Valley, Foremost	1625	581	2206	2206
1930	29	201					2206
1931	9	210					2206
1932	6	216					2206
1933	7	223					2206
1934	3	226	Lloydminster	5		5	2211
1935	2	228					2211
1936	8	236					2211
1937	15	251	Battleview-Vermilion	12	2	14	2225
1938	12	263					2225
1939	18	281					2225
1940	23	304	Brooks North East, Princess Patricia, Rainy Hills, Steveville, Toronto	131		131	2356
1941	20	324	Pouce Coupe Suffield	60 19		60 19	2435
1942	43	367	Oyen	18		18	2453
1943	34	401	Athabasca	9		9	2462
1944	56	457	Black Butte & Pinhorn Jumping Pound	34 375	4	34 379	2875
1945	56	513					2875
1946	54	567	Pendant d'Oreille Provost Elk Point	261 84 5		261 84 5	3225

1947	71	638	Dunmore	19		19	4377
			Hanna	16		16	
			Morinville	169		169	
			Smith Coulee	17		17	
			Manyberries	65		65	
			Leduc-Woodbend	858	5	863	
			St. Paul	3		3	
1948	126	764	Redwater	2		2	6088
			Pincher Creek	1680		1680	
			* Other small fields	29		29	
1949	209	973	Boyle Area	36		36	6736
			Campbell	14		14	
			Cessford	440		440	
			Excelsior	34		34	
			Lac La Biche	13		13	
			Picardville	23		23	
			Golden Spike	36		36	
			Stettler	12		12	
			Bon Accord	8		8	
			Bonnyville	3		3	
			* Other small fields	29		29	
1950	224	1197	Countess	60		60	7202
			Pelican	13		13	
			Valleyview	14		14	
			Sibbald	13		13	
			Whitelaw	316		316	
			Acheson	21		21	
			* Other small fields	29		29	
1951	456	1653	Tangent	131		131	7422
			Sturgeon	23		23	
			Wizard Lake	28		28	
			Majeau Lake	9		9	
			* Other small fields	29		29	

NOTE: Small fields adjoining one another are considered discovered at the date of the main discovery.
* The small fields totalling 116 billion cubic feet shown in Table A-1, arbitrarily, equally, assigned to the years shown.

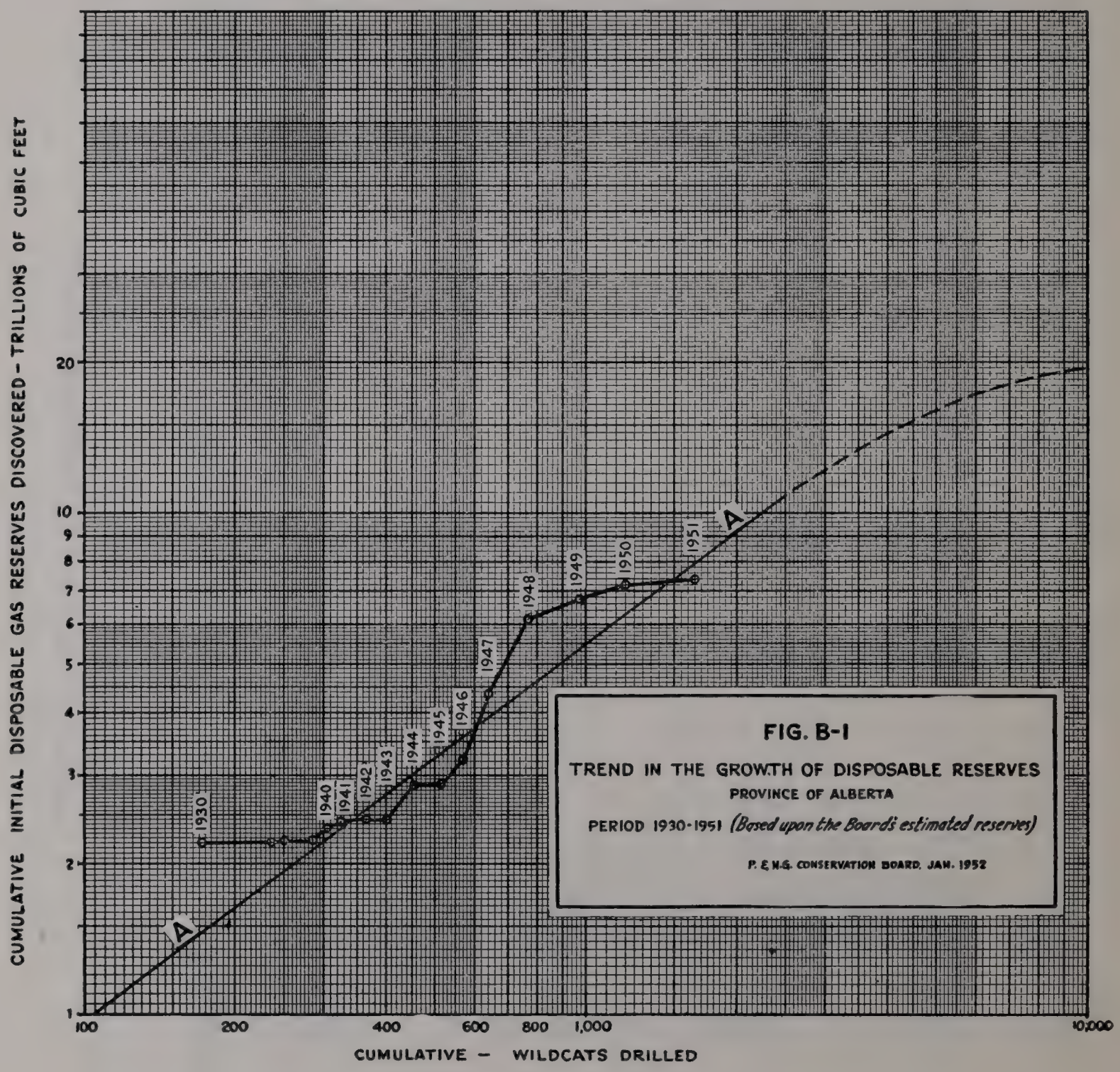


FIG. B-1

TREND IN THE GROWTH OF DISPOSABLE RESERVES
PROVINCE OF ALBERTA
PERIOD 1930-1951 *(Based upon the Board's estimated reserves)*

P. E.N.G. CONSERVATION BOARD, JAN. 1952

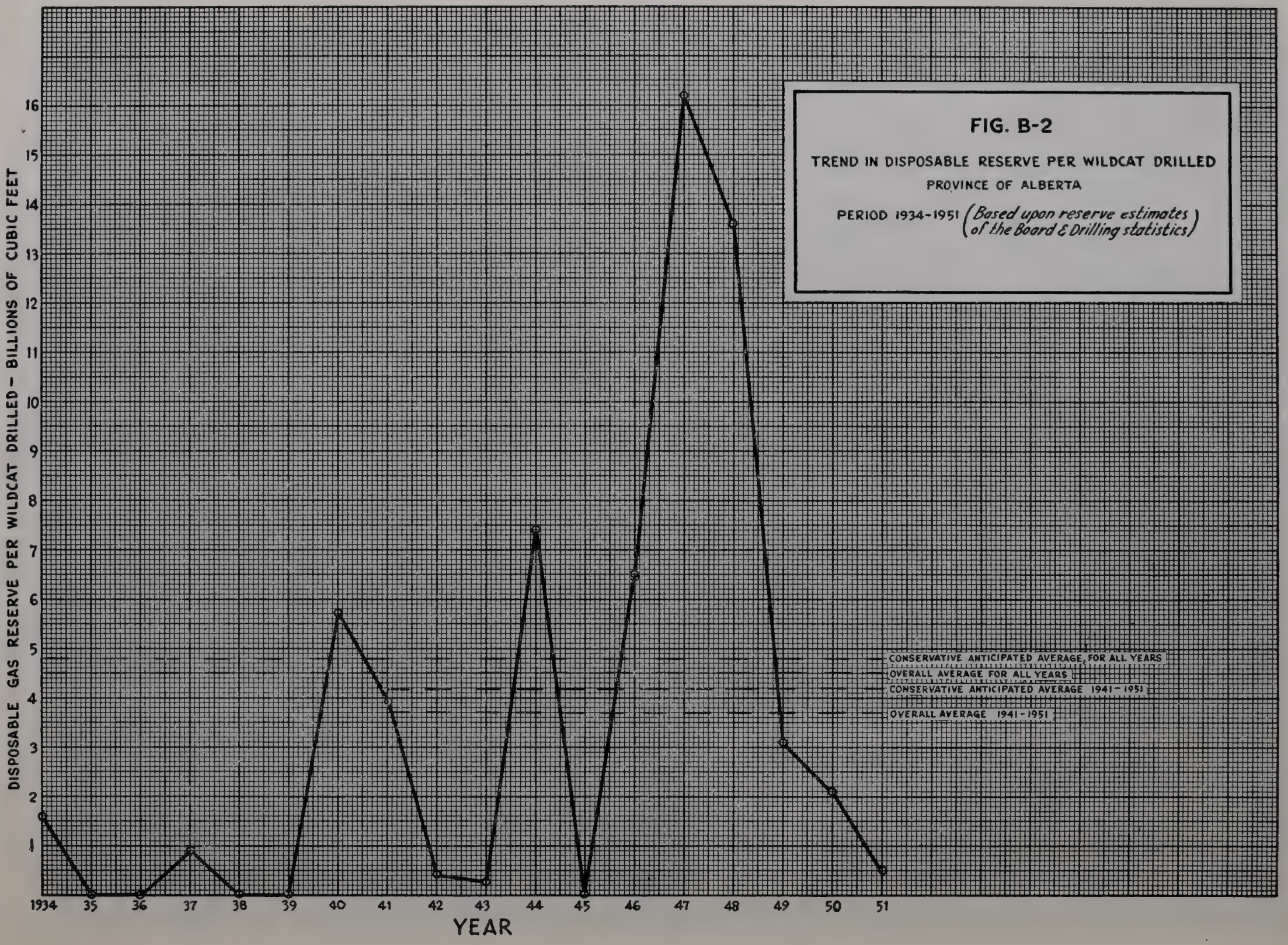


FIG. B-2

TREND IN DISPOSABLE RESERVE PER WILDCAT DRILLED

PROVINCE OF ALBERTA

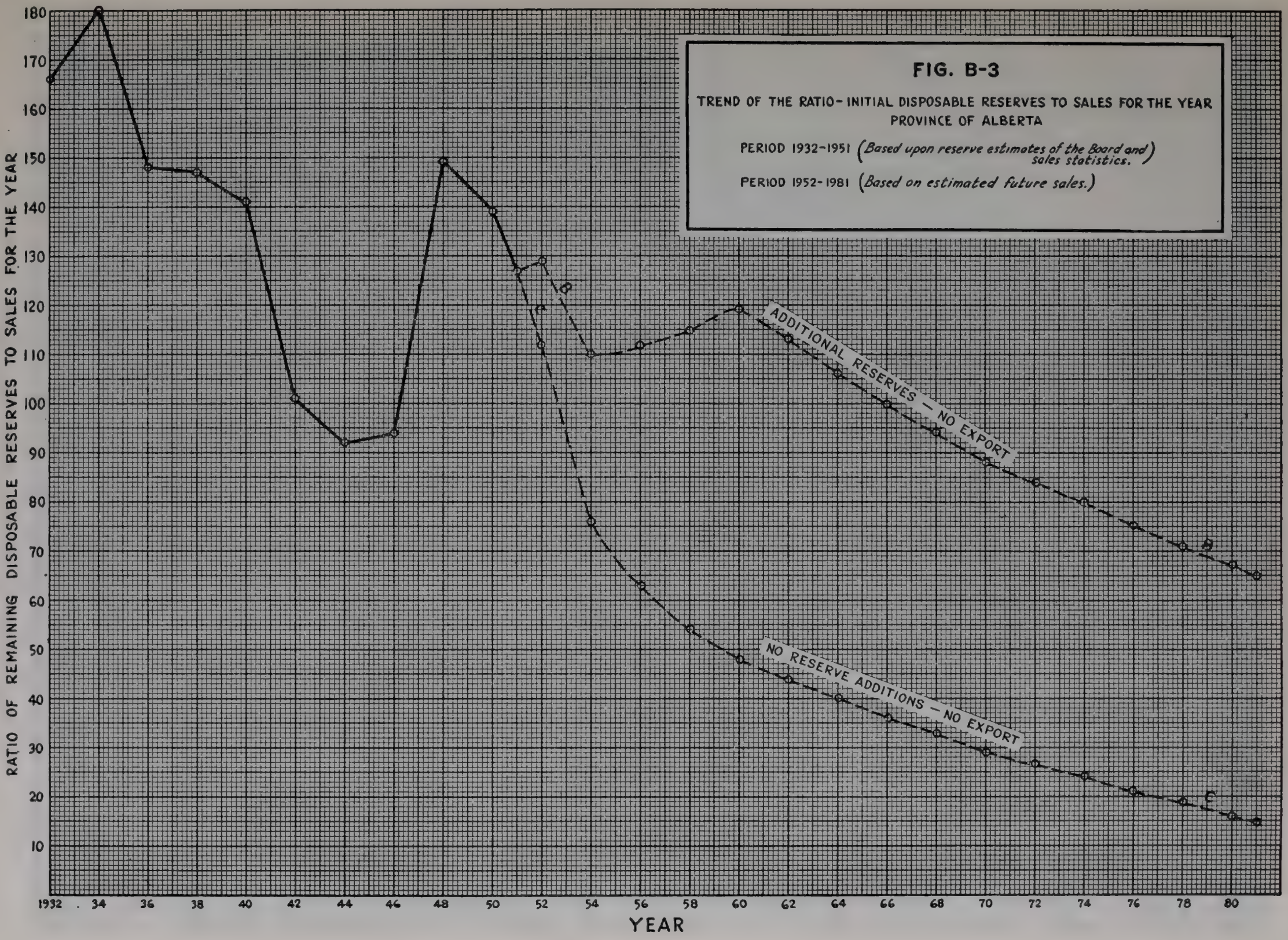
PERIOD 1934–1951 *(Based upon reserve estimates of the Board & Drilling statistics)*

FIG. B-3

TREND OF THE RATIO - INITIAL DISPOSABLE RESERVES TO SALES FOR THE YEAR
PROVINCE OF ALBERTA

PERIOD 1932-1951 *(Based upon reserve estimates of the Board and sales statistics.)*

PERIOD 1952-1981 *(Based on estimated future sales.)*



APPENDIX C

PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE

The consumption of natural gas in 1951, exclusive of field and processing plant use and exclusive of propane and butane of "LPG", was:

	Domestic billion cubic ft.	Commercial billion cubic ft.	Industrial billion cubic ft.	Total billion cubic ft.
Canadian Western Natural Gas System	8.0	4.8	10.5	23.3
Northwestern Utilities System	8.8	6.5	6.5	21.8
Other (estimated)	1.7	1.1	5.7	8.5
Total	18.5	12.4	22.7	53.6

The present peak day requirements and load factors for the Canadian Western Natural Gas Company and the Norhwestern Utilities Limited System are:

	Peak Day million cubic feet	Load Factor per cent
Canadian Western Natural Gas System	164	38.9
Northwestern Utilities System	162	36.9

In reviewing its original estimate of future requirements, the Board has had the benefit of additional evidence submitted by Mr. H. Harries, an Alberta economic consultant, on behalf of Canadian Delhi Oil Ltd. and Trans-Canada Pipe Lines Limited, and by Mr. F. A. Brownie representing both the Canadian Western Natural Gas Company Ltd. and the Northwestern Utilities Ltd. In addition, an economic survey published by the Westcoast Transmission Company Ltd. entitled "Natural Gas and the Economy of Alberta and British Columbia" was filed as an exhibit but was not formally presented as evidence by a witness who could substantiate the facts or be cross-examined on them. The Board also made use of the preliminary 1951 census figures in revising its estimates of population growth.

Estimates of Canadian Delhi Oil Ltd. and Trans-Canada Pipe Lines Ltd.

Mr. Harries submitted to the Board a comprehensive study of the natural gas requirements for the Province for the period 1951-1980. He used a different approach to that of the Board and arrived at a 30-year requirement of 3.358 trillion cubic feet, about 10% more than the Board's interim estimate. Mr. Harries used the census divisions as a convenient method of dividing up the Province into areas which were relatively homogeneous and which could be examined from a resource and population point of view. Mr. Harries considered the census division as his basic unit, and estimated the requirements of each division by studying the productive and potential productive capacity of the land and other natural resources, then relating it to population growth in the following categories:

(1) Rural—farm population;

(2) Rural—non-farm population;

(3) Urban.

Soil analysis, climatic conditions, trends in land use, opening up of additional lands for settlement, and the possibilities of more intensified use of land through irrigation schemes were all considered.

The total requirements were estimated by Mr. Harries under three main headings:

(a) Domestic and Commercial;

(b) Rural Electrification;

(c) Industrial.

(a) Domestic and Commercial.

For the main cities served with gas, per capita consumption figures together with population estimates were used in computing the requirements. The requirements for all other communities with a population of over 300 in 1946 were estimated on a per capita basis related to population growth. Two per capita figures were used—adjusted on a degree-day basis—one for communities south of Red Deer and the other for communities from Red Deer north. The per capita figures used by Mr. Harries appear high based on consumption experience to date and the 1951 census figure. This is possibly accounted for by Mr. 'Harries' estimate of population growth from 1946 to 1951 being on the low side.

Rural non-farm requirements in the areas served by Canadian Western Natural Gas Company Ltd. and Northwestern Utilities Ltd. were estimated on the basis of 10 Mcf per capita related to total population, increasing to 12 Mcf per capita in 1961. Other areas were estimated at 2 Mcf per capita, increasing to 5 Mcf per capita in 1960.

It is interesting to note that Mr. Harries' 30-year estimate for domestic and commercial consumption of 1,568.133 billion cubic feet is within 4% of the figure of 1,625.4 billion cubic feet estimated by the Board in the Interim Report for the same period. The Board figure was computed on a different basis—utilization of over-all population and per capita consumption trends in Alberta and comparisons with those in Texas, Oklahoma and elsewhere.

(b) Rural Electrification.

Mr. Harries made a very detailed study to determine the number of potential power users which, in his opinion, would be served by local generating plants using natural gas for fuel.

He utilized the 1946 census Report on Agriculture to obtain his basic data. The data for each census subdivision were analyzed in the light of past and future agricultural development to permit an estimate of the number and size of farms that would be in operation in 1961 and 1980. From these figures was deducted the number of subsistence farms, i.e., farms in 1946 which yielded less than $600.00 gross income, to arrive at the number of farm units which normally would want to utilize the benefits of electrification. In making his analysis, Mr. Harries paid particular attention to trends in land use, the introduction of irrigation to many areas, and the opening up of new areas for settlement.

On arriving at the number of farm units in each census division their location was examined with respect to existing or proposed rural electrification schemes, and those which were served or could be served from these facilities were deducted from the total to give the number of potential power users to be supplied by local systems using gas for generation purposes. He then used a figure of 2,500 kwh per potential user and a figure of 30 cubic feet of gas per kwh to arrive at his gas requirements. Under cross-examination he admitted his figures per potential user were high but stated that they included provision for the use of power to extend irrigation schemes. He also admitted that his figure of 30 cubic feet for generation might be high. He estimated there will be 86,000 farm units capable of being electrified in 1960, of which 29,000 will be served under existing and proposed plans for rural electrification, leaving 57,000 to be supplied from local plants operating with gas. He stressed the great boon these plants would be to the farms in the eastern, northeastern and northern parts of the Province which are so far remote from hydro power sources.

Under cross-examination Mr. Harries stated that small gas reserves, which might otherwise be uneconomic to produce, due to distance from markets, would be ideal for local power generation.

The Board shares Mr. Harries' views with respect to extension of rural electrification through utilization of gas resources and considers it should be given a high priority. While the Board had not estimated this requirement separately, it had been taken into consideration in estimating industrial gas requirements for power development.

(c) Industrial.

Mr. Harries divided the industrial requirements into three groups, viz.:

(1) Ordinary Industrial,

(2) Power Generation,

(3) Major Industrial.

Ordinary industrial requirements were defined as those linked with urban population growth comprising restaurants, laundries, small food processors, etc., and were estimated at 10 Mcf per capita of urban population.

Power Generation.

Mr. Harries estimated gas requirements for power generation, exclusive of rural electrification, from 1951 to 1980 at 276.6 billion cubic feet. He stated under cross-examination he had assumed no hydro power would be generated outside of the Bow River but admitted he had heard about potential sites on both the Athabasca and North Saskatchewan Rivers. He further stated that his estimates were based on replacing coal with gas but admitted the possibility of coal competing with gas if a power plant was located on or beside a coal field, such as at Wabamun.

It is noteworthy that even with the assumption made by Mr. Harries, his estimate of total annual requirements of gas for power generation in 1960, including his figure for rural electrification, is some 7.4 billion cubic feet less than the 20 billion cubic feet estimated by the Alberta Power Commission.

Major Industrial Requirements.

Mr. Harries estimated the requirements for the years 1951, 1961, and 1981 and the figures for the intervening years were calculated from these. The requirements were divided between Canadian Western Natural Gas Company Ltd., Northwestern Utilities Ltd. and local systems. Large petrochemical plants, with high load factor requirements, were not included in the major utility estimates as Mr. Harries did not think they could obtain as good a price from the utilities as they could by dealing directly with gas producers.

Canadian Western Natural Gas Company Ltd. and Northwestern Utilities Ltd. industrial requirements for 1961 were calculated on a basis of a 50% increase over the 1951 figures. Canadian Western Natural Gas Company Ltd. requirements for 1980 were based on a 25% increase of the 1961 requirements and for Northwestern Utilities Ltd. 100% increase over the 1961 requirements. The 1961 requirements for local systems were calculated on the basis that there would be two large consumers with 10 billion cubic feet per year and five other users each using one billion cubic feet per year. To this amount Mr. Harries added an estimated figure of 4.3 billion cubic feet for the Medicine Hat-Redcliff area. The 1981 figure was based on adding 10 billion cubic feet to the 1961 figure.

Mr. Harries' total estimate of industrial requirements for the thirty years is about 20% higher than that shown in the Board's Interim Report—his over-all requirements for thirty years are about 10% higher. He stated under cross-examination that he thought his figures were a maximum and when asked if he thought the Board should revise its figures he said, no, on the basis that he had no reason to suppose his total estimate any better than the Board's.

Requirements as estimated by Mr. Harries for the period 1951 to 1980 were as follows:

	Billion cubic feet
Domestic and Commercial	1,568.133
Rural Electrification	111.808
Industrial	1,678.191
	3,358.132

Views of Canadian Western Natural Gas Company Ltd. and Northwestern Utilities Ltd.

Mr. Brownie submitted to the Board a breakdown of the original estimates submitted on behalf of Canadian Western and Northwestern Utilities to show for the years 1950, 1960, 1970 and 1980 the requirements under the three categories of domestic, commercial and industrial. To these estimates he added the Board's estimates of total requirements for the remainder of the Province for the same years by categories. Mr. Brownie also submitted for comparative purposes a breakdown of the Board's market requirements as shown in the Interim Report, for the Canadian Western Natural Gas Company Ltd., Northwestern Utilities Ltd. and the remainder of the Province in the same form as their own estimates.

The domestic requirements as estimated by the utility companies and the Board were in close agreement.

Mr. Brownie commented on the Board's estimate of commercial requirements which was some 30% higher than that of the companies. He explained that while the trend from 1930 to 1944 might show that commercial requirements were increasing more in proportion to domestic, recent figures do not substantiate this.

Mr. Brownie pointed out that the companies' estimate of industrial requirements did not include provision for "extraordinary increases such as petrochemical industries, dispersal of industry, etc." He stated that the Board's industrial estimates—considerably higher than those of his companies—might be on the low side in view of recent industrial developments but that he would accept the Board's over-all estimate on the basis that the over-generous allowance for commercial requirements would make up for the shortage in industrial requirements.

At a later stage in the hearings Mr. Brownie presented another brief on behalf of the two major utilities dealing with the long-range supply of gas for Alberta consumers, the field price situation and the inherent problems in gas export. In his brief he made reference to the fact that the Board in its Interim Report had selected a 30-year period for the protection of the long-range requirements of the Province and he suggested that a factor of safety might be added to these requirements. Upon being examined on this point, Mr. Brownie suggested 25% as the factor of safety.

Brief Entitled Natural Gas and the Economy of Alberta and British Columbia

The economic survey filed by the Westcoast Transmission Company Ltd. comprises a detailed survey of the Province's economy, with particular reference to the utilization of its natural gas resources. The survey contains two reports, one dealing with the over-all economic factors (prepared by Dr. Nathanael Engle, Consulting Economist, University of Washington), and the other dealing with gas reserves (compiled by Link & Nauss Ltd., Consulting Geologists).

Dr. Engle states that the requirements for a balanced economy in Alberta depend on two major factors: (1) development of agriculture; and (2) industrial diversification. He emphasizes the importance of an expanding agriculture and deplores the trend of population away from the farms to the cities and towns and the decline in the percent of the total gross value of the product of the Province which is contributed by agriculture. He discusses three projects—irrigation, rural electrification, and the building of more and better roads—which would materially help in the development of agriculture and their importance.

In dealing with industrial diversification Dr. Engle emphasizes a diversified and well-balanced energy base as being the primary requirement for industrial development. He states that electrical energy is a major power base of modern industry and comments that the "under-development of electrical energy is one of the noticeably weak spots in the expansion of the energy base in Alberta". He finds this hard to understand in view of the Province being so well supplied with both water power and fuel for producing electrical energy. In reviewing the power situation from an efficiency point of view, he refers to the necessity of complementing hydro-electric power with power generated from fuel due to the difficulty of providing a hydro-electric water supply throughout the year. He states as his opinion that coal is the fuel which should be used for power genera-

tion. He considers that power plants established on or near coal fields can generate power at a relatively low cost. He also mentions coal as possible raw material for the chemical industry.

The report of Link & Nauss Ltd. reviews, inter alia, Alberta's future requirements and states that the various estimators agree well on the domestic and commercial requirements but there is disagreement on the future industrial requirements because of the difficulty in predicting the number of new industries, particularly petrochemical plants, that may be established in the Province during the next 30 years. Link & Nauss quote from the report of Dr. Engle, in which he compares the industrial requirements as estimated by the Board with an estimate prepared by himself. Dr. Engle took issue with the Board's method of forecasting the industrial requirements. In his projection he used a per capita consumption per industrial employee. He took the long-range trend from 1906-1947 and projected it to 1980 and arrived at a range of industrial employees as at 1960 of 28,685 to 35,375, which would increase to 35,400 to 59,100 by 1980.

He considered that the consumption of natural gas for industrial use is statistically more properly a function of the number of industrial workers than of total population. He found that the average industrial consumption of natural gas per manufacturing worker in 1950 to be 662.3 Mcf and that the average annual increment in the use of natural gas per industrial employee for the ten years prior to 1950 was 44.9 Mcf per industrial employee. He stated that in line with the assumption made by the Board in its Interim Report, namely, "that the per capita figure was assumed to increase at a rate of about one-half of that which has been experienced over the past ten years," he assumed that the consumption per industrial employee would increase by 22.45 Mcf per year to a figure of 824.5 Mcf in 1960. Dr. Engle apparently misinterpreted the assumption made by the Board to mean the actual annual Mcf increment per capita rather than the percentage rate of increase which the Board used. He estimated total industrial requirements for the 30-year period as ranging from 743.9 billion cubic feet to 1,022.8 billion cubic feet with an intermediate figure of 868.4 billion cubic feet. This latter figure is approximately 566 billion cubic feet less than the Board's original estimate.

With the exception of Trans-Canada Pipe Lines, whose estimate of requirements by Mr. Harries has been commented on, and Westcoast Transmission Company Ltd., who filed the economic survey, none of the other applicants submitted further information with respect to the Province's requirements and more or less intimated that they accepted the figures in the Board's Interim Report.

Alberta Population

The preliminary census figures for 1951 indicate that the Interim Report long-term forecast of population increase may be low. Population in the Province increased from 803,000 in 1946 to 936,000 in 1951, corresponding to a growth of 3.1% per year for the 5-year period. The Board has now assumed a population growth at the rate of 3% per year from 1951 to 1960; 2% from 1961 to 1970 and 1½% from then on. See Figure C-1—population trends.

Using Mr. Harries' definition of urban population, i.e., population of cities, towns and villages having a population of over 300 as of 1946, the ratio of urban population to the total population increased at the rate of 2.3% per year for the period 1946 to 1951 as compared with 2% for the period 1941 to 1946. On the same basis, the rural population increased from 458,030 in 1946 to 463,022 in 1951, a relatively small growth at the rate of .2% per year. During the period 1941 to 1946 rural population decreased by approximately 40,000. No doubt this was caused by the requirements of the Armed Services and the need for manpower in war industries.

The Board concurs in the views expressed by Dr. Engle as to the requirements for an expanding agriculture. It believes that with an accelerated tempo of rural electrification and the continued expansion of our road-building programme to improve the amenities of rural life, together with the irrigation schemes under way and planned, and the opening up of new areas for settlement, our agriculture and rural population will show a steady growth.

Domestic Requirements

Per capita consumption of the Province for 1951 for domestic purposes was 19.8 Mcf (based on the preliminary census population figures and corrected to a normal degree-day basis). This actual figure is about 10% less than the Board's forecast of 22.1 Mcf per capita. The Interim

Report per capita figure was high partly because it incorrectly included some of the small industrial requirements of the remainder of the Province and partly because it was based upon population estimates since found to be too low. The total gas consumed in 1951 for domestic purposes (corrected to normal degree-day basis) was 18.5 billion cubic feet and was about 8% below the Interim Report estimate of 20.1 billion cubic feet.

It has been assumed that the urban population will be approximately 60% of the total population by 1960. This allows for a growth in urban population at the rate of 5.1% and rural population of .5% per year, as indicated in Figure C-1. It has also been assumed that all the urban population will be served with gas by 1960 and on this basis the per capita consumption is estimated to increase from 19.8 in 1951 to 27.5 in 1960. As indicated in the Interim Report, the Board is reluctant to extrapolate the per capita figures beyond 1960. Moreover, it seems to the Board that the present per capita growth may tend to level out within the next decade. Accordingly, the per capita figures are assumed constant from 1960 onward.

Total domestic requirements are now estimated at 1114.7 billion cubic feet—an increase of 241.0 billion cubic feet over the previous estimate. Table C-1 gives the details by years.

Commercial Requirements

Commercial requirements have been calculated in the same manner as the domestic, with per capita consumption estimated to increase from 13.2 in 1951 to 19 in 1960. These per capita figures are less than those used in the Interim Report which ranged from 16 in 1951 to 21 in 1960. Actual per capita consumption in 1951 was 13.2 as compared to 16 originally estimated. Even making allowance for the adjustment of population, the Board's interim figure of 16 appears high. This confirms the evidence of Mr. F. A. Brownie that while the growth trend from 1930 to 1944 might indicate a greater proportional increase in commercial consumption compared with domestic, recent experience does not bear this out and the relative growth appears now to be nearly the same.

Industrial Requirements

In its Interim Report the Board dealt at some length with the possibility of industrial expansion through the utilization of our energy resources and raw material—particularly the hydrocarbon compounds obtained through the processing of oil and gas. Developments since the preparation of the Interim Report suggest a future for the petrochemical industry even greater than contemplated at that time. Two large petrochemical plants are now under construction and the establishment of a large ore-processing plant also has been announced.

It might be appropriate to discuss the products which the two chemical plants intend to manufacture and their raw material and energy requirements.

The Canadian Chemical Company is building a plant to manufacture acetic acid, acetic anhydride and a range of other chemicals. The bulk of the acetic anhydride will be used to convert cellulose (shipped from the Canadian Celanese new pulp mill near Terrace, B.C.) to cellulose acetate. It is expected that most of the cellulose acetate will be exported to the world market with little or none of it being shipped to the United States. Part of the acetic anhydride, acetic acid and other chemicals will be sold on the Canadian and export market. The estimated cost of this plant is in the neighbourhood of $50,000,000.00. The raw materials to be used are butanes obtained from the processing of wet gas and refinery gases containing propylene and butylenes. The plant will require a large amount of natural gas to provide for heat and power.

Canadian Industries Ltd., who are building the other plant, intend to manufacture polythene, a high-priced versatile plastic developed in the last few years. The estimated cost of this plant is some $14,000,000.00. The principal raw material used in the manufacture of polythene is ethylene produced from ethane, which the company will obtain by processing the high ethane residue gas from the Devon Gas Conservation Plant. After extraction of the ethane, part of the residue gas will be utilized as plant fuel and the balance will be used in the Northwestern Utilities Ltd. system.

The ore-processing plant is to be built by Sherritt Gordon Mines Ltd. and will produce large quantities of refined nickle and cobalt, together with copper sulphide and ammonium sulphate

fertilizer. The cost of the plant is estimated at about $17,000,000.00. Ammonia used in the refining process will be manufactured from gas, which also will be required as fuel.

The establishment of the aforementioned plants in the Province corroborates the views expressed by Dr. J. R. Donald, well-known Canadian Consulting Chemical Engineer, in his recent address to the Alberta Northwest Chamber of Mines. He stated ". . . the handicap of freight charges to Eastern Canadian markets becomes less onerous under two conditions:

(1) where the hydrocarbon material and energy requirements in the manufacture of a chemical are high, and, therefore, manufacturing costs are substantially benefitted by location in Alberta;

(2) where the investment per ton of chemical produced is high, and must be protected by assurance of an adequate, long-term supply of essential raw materials."

Dr. Donald also made refence to the manufacture of low-price chemicals in the Province as follows:

"Possibilities are also good where low-priced chemicals can be consumed in the West in sufficient quantities to warrant manufacture and THIS WILL OCCUR THROUGH EXPANSION OF SECONDARY INDUSTRIES with population growth in the West."

In its Interim Report the Board divided the industrial use of natural gas and its related compounds into the following categories:

(1) Use of dry or lean natural gas as a fuel for industrial processes, steam generation, etc.

(2) Use of dry or lean natural gas, primarily for its methane content, for the manufacture of carbon black, ammonia and a relatively few other products which may be produced economically using methane as a raw material.

(3) Use of ethane recovered from dry or wet natural gas for conversion to ethylene and then to other products.

(4) Use of L.P.G. (propane and/or butanes) for conversion by partial oxidation or other processes to a wide range of chemicals; use of butane for conversion to butadiene; use of isobutane for the manufacture of alkylate—important constituent of aviation gasoline.

Under category (2) it has been assumed that the requirements for ammonia will be more than doubled before 1960 after taking into consideration the requirements of the Sherritt Gordon Mines Ltd.

Provision has also been made for the possible development of a carbon black industry within the Province. (This possibility may seem remote at the present time in the light of the oil furnace carbon black plant of the Cabot Carbon of Canada Ltd. now under construction in Sarnia. Increase in the volume or variety of carbon black demand or the dispersal and expansion of the synthetic rubber industry, however, might well favour Alberta development.)

As mentioned previously, ethane (category 3) is to be used by Canadian Industries Ltd. at their Edmonton plant to manufacture polythene. Provision has been made for the full requirements of their plant as now contemplated and allowances have also been made for further use of ethane in the manufacture of other products.

Under category (4) Canadian Chemical Co. Ltd. will be a large consumer with an initial consumption of some 60,000 imperial gallons per day of butanes, propylene and butylenes. Some propane may also be used—however, there is a large and growing demand for propane as a domestic and commercial fuel to meet the requirements of farmers and rural communities in Alberta and our neighbouring provinces.

The Board has no doubt that there will be a greater demand for L.P.G. (i.e., propane and/or butanes) as a raw material, but any great expansion will depend on the availability of L.P.G. at an attractive price. As pointed out in the Interim Report, L.P.G. from the processing of wet gas can only be made available at attractive prices if there is a market for the residue gas at a

reasonable price. In any case, the Board will not permit, beyond reasonable economic limits, the flaring of gas produced with oil or condensate. In this connection it may be well to refer again to the Pincher Creek field which could make available large quantities of L.P.G. besides natural gasoline and sulphur when a market for the residue gas is provided.

The Board has endeavoured to take a realistic view of the increased industrial use of L.P.G. as a raw material in relation to quantities which can be made available and in the knowledge that further discoveries of wet gas reserves either alone or associated with oil will supply not only the necessary raw materials but the raw gas for fuel purposes.

The large requirements for dry or residue natural gas is, of course, under category (1) and includes:

(a) Fuel for small industries such as laundries, cleaners, restaurants, bakeries, etc.

(b) Fuel for major industries such as agricultural processing plants, smelting operations, ordinary manufacturing plants.

(c) Fuel for processing and manufacturing plants using gas and related compounds as raw materials as per categories (2), (3) and (4).

The requirements for (a) can be associated directly with population growth along the lines suggested by Mr. Harries. Under (b) previous experience has been taken into consideration, together with the evidence submitted by Messrs. Harries and Brownie as to future requirements.

In estimating the requirements under (c) the Board has had the benefit of information supplied by the companies who are now building or have announced their intention to build plants, as to their initial requirements and their tentative plans for the future. No provision is made in the industrial requirements for fuel consumed in gas-processing plants located at fields such as Turner Valley, Jumping Pound and Leduc. Provision is made for these requirements in the "Surface Discount Factor" applied to producible gas to arrive at the disposable gas figure for any field.

With respect to gas for power development, the Alberta Power Commission estimated requirements at 20 billion cubic feet in 1960 as compared with Mr. Harries' estimate of 12.4 billion cubic feet which includes his total for rural electrification. The Power Commission based its estimate on the assumption of 20 cubic feet of gas being required to generate one kilowatt hour of electricity. This figure appears high in view of the recent improvements in the operating efficiency of conventional power stations and new gas turbine units.

Mr. Harries' estimate may be on the low side if, as he assumed, gas is to supplant coal entirely for power generation. The Board does not agree that gas will supplement coal completely for power generation but believes that coal has its place in Alberta power development and will be utilized in some of the new plants which will be required to supplement hydro development.

The possible use of atomic energy for power development should not be overlooked. Right Honourable C. D. Howe, Minister of Defence Production, in a recent address at the University of Toronto stated:

"I believe that the majority of those in this audience will live to see large atomic power plants deliver primary power to the major power grids of this country, and to see the development of types of atomic power plants that will bring the life blood of industry to areas that cannot be supplied with hydro power."

"Thus, atomic power is destined to offer a new tool for engineers with which to roll back the frontiers of Canada."

The Board is still of the opinion that consumption per capita (of total population) is a better yardstick for forecasting industrial requirements than consumption of gas per industrial employee as suggested by Dr. Engle. This holds particularly in the case of Alberta where up to the present the processing of agricultural products, reflecting a relative low consumption per employee,

has been the major industry whereas the Province is now entering a period of expansion in the petrochemical and related industries with a relative high consumption per employee.

On the basis of evidence adduced, consideration of past trends together with information in its possession relating to the requirements of new industries and possible expansion, the Board has assumed that the per capita industrial consumption will rise sharply within the next few years levelling off about 1960 at a figure of 56.0 Mcf. as compared with 24.3 Mcf. in 1951. This corresponds with an average annual per capita increase of 9.7%. The Interim Report estimate of 42 Mcf. per capita in 1960, represented an average annual increase from 1950 to 1960 of 8.5%.

Revised Projections

Figure C-2 shows the revised trends in per capita consumption for domestic, commercial and industrial requirements. A re-allocation as between the three categories has been made in the figures for past consumption of local systems to make allowance for ordinary industrial requirements which previously had been included in the domestic and commercial totals. It is to be noted that, as in the Interim Report, the per capita trends have not been extrapolated beyond 1960 and the 1960 per capita figures have been assumed to extend to 1981.

The total requirements under each category were obtained by combining the per capita amounts shown in Figure C-2 with the population projection of Figure C-1. These requirements are shown graphically in Figure C-3 and in tabular form in Table C-1. Figure C-4 has been prepared to compare Mr. Harries' estimate with that of the Board. Mr. Harries estimated domestic and commercial requirements together, and the rural electrification requirements have been included in his industrial figure.

The Board now estimates the requirements of the Province for the thirty-year period, 1952 to 1981, as follows:

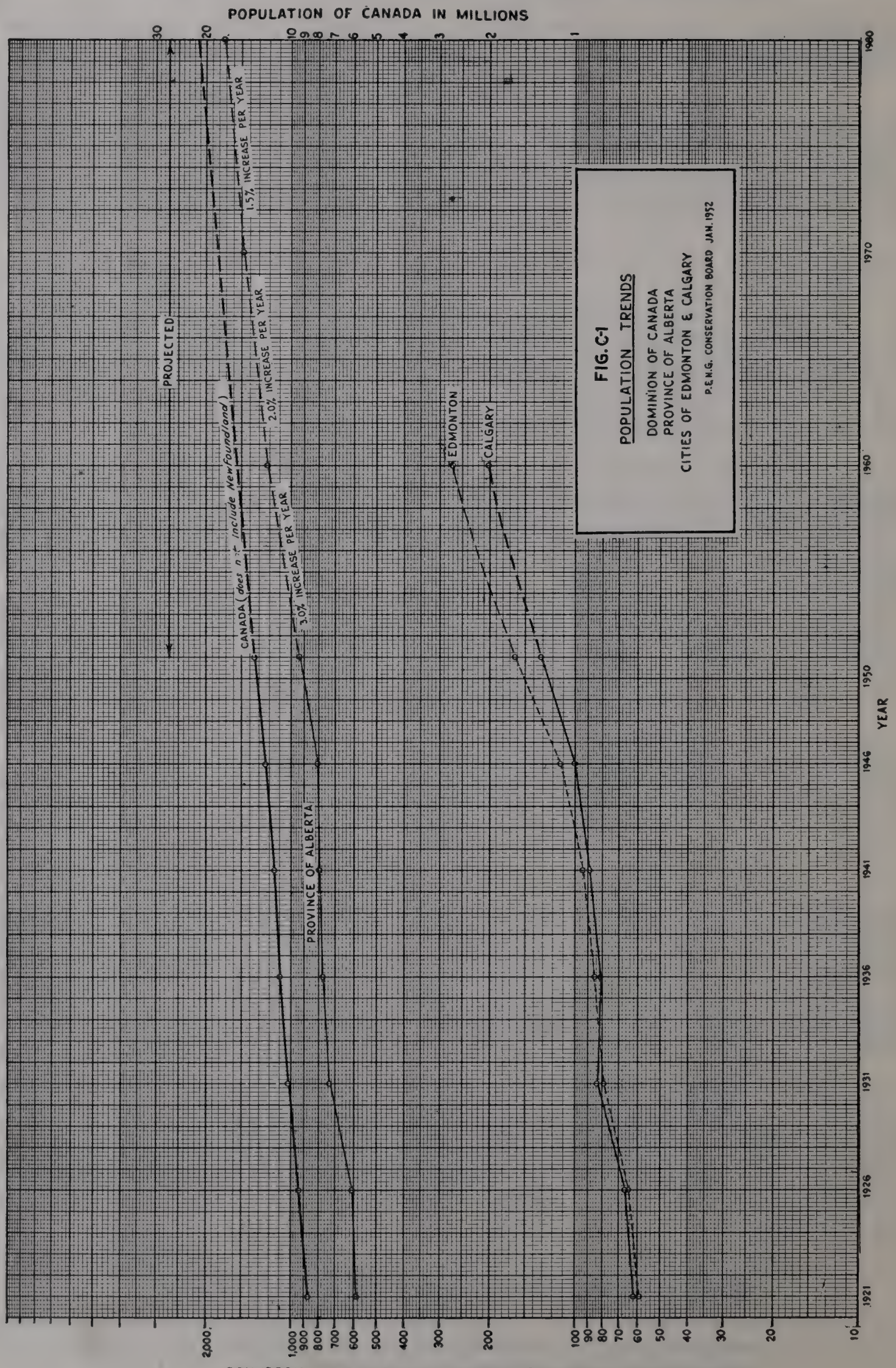
	Interim Report billion cubic feet	Revised billion cubic feet
Domestic	873.7	1,114.7
Commercial	751.7	763.5
Industrial	1,434.5	2,248.7
Total	3,059.9	4,126.9

The allocation of these requirements to the areas tributary to the Canadian Western Natural Gas Company Ltd. system, the Northwestern Utilities, Limited system and the remainder of the Province is shown in Table C-2. This table also reflects the estimated peak day requirements and the load factors for the three areas. The estimated load factors are believed consistent with the relative industrial growth expected in the various areas. As pointed out in the Interim Report any allocation of requirements as between areas of the Province and any estimates of future load factors must be somewhat arbitrary. The present one represents the Board's best judgment in the matter.

The requirements of the area tributary to the Northwestern Utilities, Limited system are estimated to be 2,085.9 billion cubic feet, an increase of 552.3 billion cubic feet over the estimate in the Interim Report—reflecting the large industrial potential in the Edmonton area. The total for the area tributary to the Canadian Western Natural Gas Company Ltd., system of 1,298.2 represents an increase of 59.6 billion cubic feet over the previous estimate. Estimated consumption for the remainder of the Province has been increased from 266.7 billion cubic feet to 742.8 billion cubic feet in the belief that:

(a) power plants for rural electrification and other new industries will be influenced by the saving in transportation costs to locate close to gas fields.

(b) all urban communities (i.e. communities with a 1946 population of over 300) now not served with gas will be supplied either by the development of local fields or from main transmission and gathering lines.


POPULATION OF CANADA IN MILLIONS
30
20
10
9
8
7
6
5
4
3
2
1
PROJECTED
CANADA (does not include Newfoundland)
1.5% INCREASE PER YEAR
2.0% INCREASE PER YEAR
3.0% INCREASE PER YEAR
EDMONTON
CALGARY
PROVINCE OF ALBERTA
FIG. C-1
POPULATION TRENDS
DOMINION OF CANADA
PROVINCE OF ALBERTA
CITIES OF EDMONTON & CALGARY
P.E.N.G. CONSERVATION BOARD JAN. 1952
1980
1970
1960
1950
1946
1941
1936
1931
1926
1921
YEAR
POPULATIONS OF EDMONTON, CALGARY AND ALBERTA IN THOUSANDS
2,000
1,000
900
800
700
600
500
400
300
200
100
90
80
70
60
50
40
30
20
10

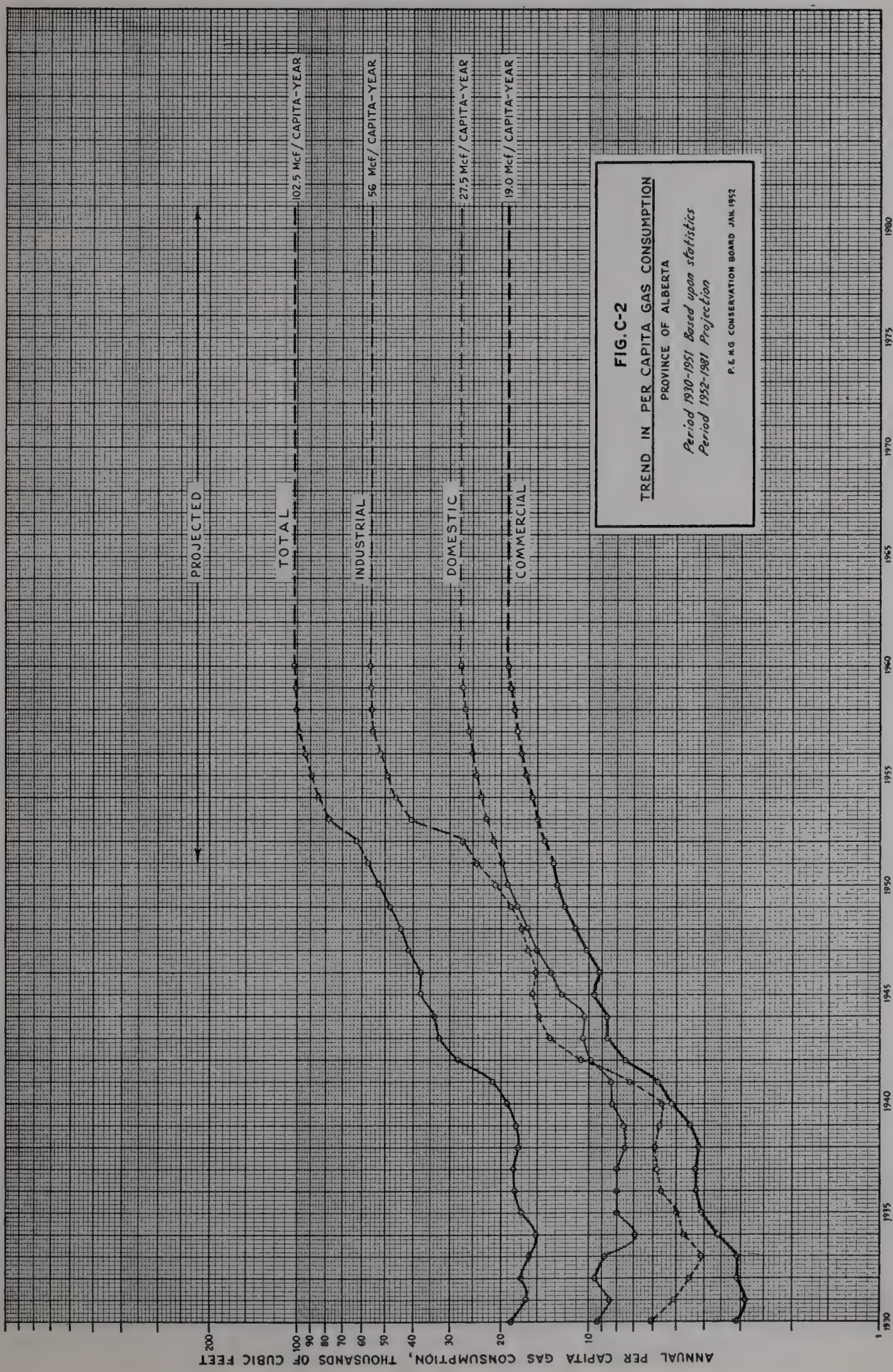


FIG. C-2
TREND IN PER CAPITA GAS CONSUMPTION
PROVINCE OF ALBERTA
Period 1930-1951 Based upon statistics
Period 1952-1981 Projection
P.E.N.G CONSERVATION BOARD JAN. 1952
PROJECTED
TOTAL
102.5 Mcf/CAPITA-YEAR
INDUSTRIAL
56 Mcf/CAPITA-YEAR
DOMESTIC
27.5 Mcf/CAPITA-YEAR
COMMERCIAL
19.0 Mcf/CAPITA-YEAR
ANNUAL PER CAPITA GAS CONSUMPTION, THOUSANDS OF CUBIC FEET
200
100
90
80
70
60
50
40
30
20
10
1
1930
1935
1940
1945
1950
1955
1960
1965
1970
1975
1980
YEAR

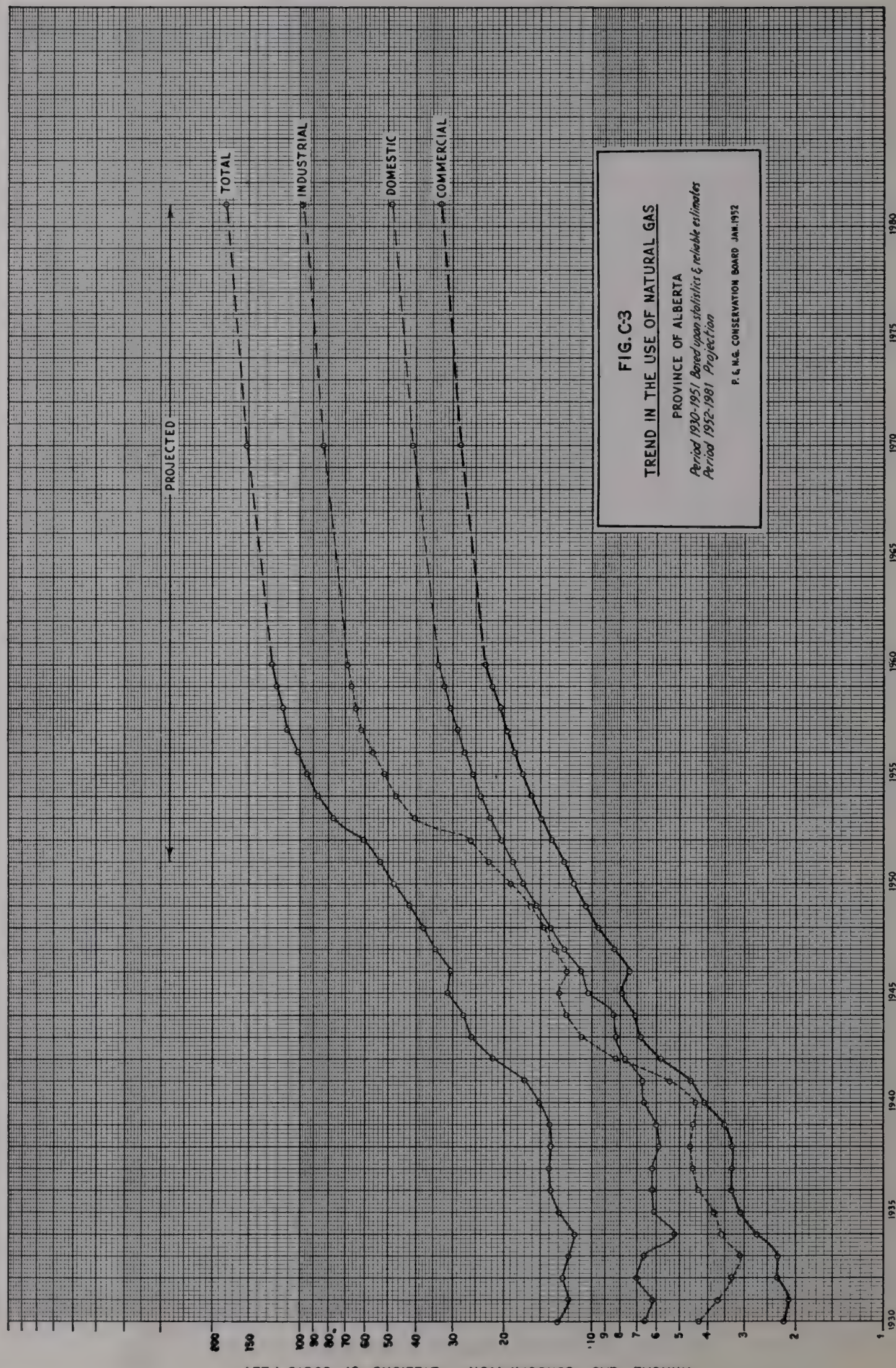


FIG. C-3
TREND IN THE USE OF NATURAL GAS
PROVINCE OF ALBERTA
Period 1930-1951 Based upon statistics & reliable estimates
Period 1952-1981 Projection
P. & N.G. CONSERVATION BOARD JAN. 1952
TOTAL
INDUSTRIAL
DOMESTIC
COMMERCIAL
PROJECTED
ANNUAL GAS CONSUMPTION - BILLIONS OF CUBIC FEET
YEAR
1930
1935
1940
1945
1950
1955
1960
1965
1970
1975
1980

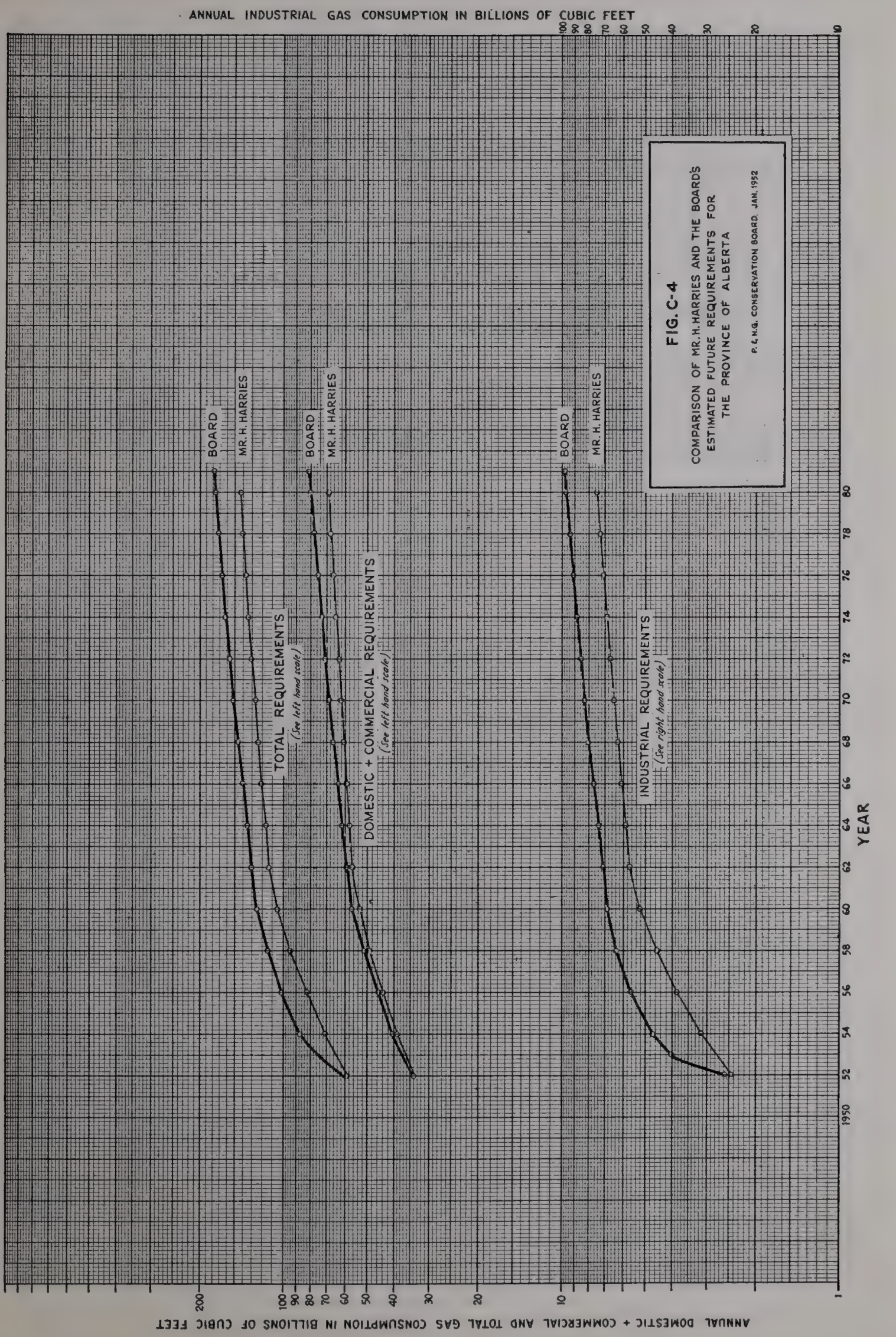

ANNUAL INDUSTRIAL GAS CONSUMPTION IN BILLIONS OF CUBIC FEET
ANNUAL DOMESTIC + COMMERCIAL AND TOTAL GAS CONSUMPTION IN BILLIONS OF CUBIC FEET
YEAR
1950
TOTAL REQUIREMENTS
(See left hand scale)
DOMESTIC + COMMERCIAL REQUIREMENTS
(See left hand scale)
INDUSTRIAL REQUIREMENTS
(See right hand scale)
BOARD
MR. H. HARRIES
BOARD
MR. H. HARRIES
BOARD
MR. H. HARRIES
FIG. C-4
COMPARISON OF MR. H. HARRIES AND THE BOARD'S ESTIMATED FUTURE REQUIREMENTS FOR THE PROVINCE OF ALBERTA
P. & N.G. CONSERVATION BOARD. JAN. 1952

Table C-1

ESTIMATE OF NATURAL GAS REQUIREMENTS

Province of Alberta, January 1, 1952—December 31, 1981.
(Corresponds with the projections of Figure C-3)

1	2	3	4	5
Year	DOMESTIC billions of cubic feet	COMMERCIAL billions of cubic feet	INDUSTRIAL billions of cubic feet	TOTAL billions of cubic feet
1952	20.5	13.8	26.0	60.3
1953	22.3	14.9	40.2	77.4
1954	24.0	16.1	47.0	87.1
1955	25.6	17.3	51.4	94.3
1956	27.2	18.5	56.3	102.0
1957	28.9	19.6	61.8	110.3
1958	30.6	20.7	64.0	115.3
1959	32.2	22.0	66.4	120.6
1960	33.6	23.2	68.7	125.5
1961	34.3	23.6	69.7	127.6
1962	35.0	24.1	71.1	130.2
1963	35.7	24.6	72.6	132.9
1964	36.4	25.1	74.0	135.5
1965	37.1	25.6	75.5	138.2
1966	37.9	26.0	77.0	140.9
1967	38.7	26.5	78.5	143.7
1968	39.5	27.0	80.1	146.6
1969	40.2	27.6	81.7	149.5
1970	41.0	28.2	83.3	152.5
1971	41.6	28.6	84.6	154.8
1972	42.3	29.0	85.8	157.1
1973	42.9	29.5	87.1	159.5
1974	43.6	29.8	88.4	161.8
1975	44.2	30.3	89.8	164.3
1976	44.9	30.8	91.1	166.8
1977	45.5	31.3	92.5	169.3
1978	46.2	31.7	93.9	171.8
1979	46.9	32.2	95.3	174.4
1980	47.6	32.7	96.7	177.0
1981	48.3	33.2	98.2	179.7
Totals	1114.7	763.5	2248.7	4126.9

Table C-2

ESTIMATE OF NATURAL GAS REQUIREMENTS

Province of Alberta, January 1, 1952 — December 31, 1981

Allocation Between Areas Tributary to the Distributing Systems

1	2	3	4	5	6	7	8	9	10	11	12	13
	Area tributary to C.W.N.G. system			Area tributary to N.U.L. system			Remainder of the Province			Total Provincial Requirements		
Year	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent
1952	26.2	179	40	24.0	178	37	10.1	69	40	60.3	426	38.8
1953	27.9	191	40	36.3	221	45	13.2	90	40	77.4	502	42.3
1954	29.6	203	40	42.9	245	48	14.6	100	40	87.1	548	43.5
1955	31.2	214	40	47.0	268	48	16.1	110	40	94.3	592	43.6
1956	32.8	225	40	51.7	289	49	17.5	120	40	102.0	634	44.1
1957	34.4	236	40	57.0	312	50	18.9	129	40	110.3	677	44.6
1958	35.9	246	40	59.1	324	50	20.3	139	40	115.3	709	44.6
1959	37.5	257	40	61.5	344	49	21.6	148	40	120.6	749	44.1
1960	38.9	266	40	63.7	356	49	22.9	157	40	125.5	779	44.1
1961	39.6	271	40	64.8	362	49	23.2	159	40	127.6	792	44.1
1962	40.4	277	40	66.1	369	49	23.7	162	40	130.2	808	44.1
1963	41.3	283	40	67.5	377	49	24.1	165	40	132.9	825	44.1
1964	42.1	288	40	68.8	385	49	24.6	168	40	135.5	841	44.1
1965	42.9	294	40	70.2	392	49	25.1	172	40	138.2	858	44.1
1966	43.7	299	40	71.6	400	49	25.6	175	40	140.9	874	44.1
1967	44.6	305	40	73.0	408	49	26.1	179	40	143.7	892	44.1
1968	45.5	312	40	74.5	417	49	26.6	182	40	146.6	911	44.1
1969	46.4	318	40	76.0	425	49	27.1	186	40	149.5	929	44.1
1970	47.3	324	40	77.6	434	49	27.6	189	40	152.5	947	44.1
1971	48.1	329	40	78.6	439	49	28.1	192	40	154.8	960	44.1
1972	48.8	334	40	79.7	446	49	28.6	196	40	157.1	976	44.1
1973	49.5	339	40	81.0	453	49	29.0	199	40	159.5	991	44.1
1974	50.2	344	40	82.2	460	49	29.4	201	40	161.8	1005	44.1
1975	51.0	349	40	83.4	466	49	29.9	205	40	164.3	1020	44.1
1976	51.7	354	40	84.8	474	49	30.3	208	40	166.8	1036	44.1
1977	52.5	360	40	86.0	481	49	30.8	211	40	169.3	1052	44.1
1978	53.3	365	40	87.2	488	49	31.3	214	40	171.8	1067	44.1
1979	54.1	371	40	88.5	495	49	31.8	218	40	174.4	1084	44.1
1980	55.0	377	40	89.9	503	49	32.1	220	40	177.0	1100	44.1
1981	55.8	382	40	91.3	510	49	32.6	223	40	179.7	1115	44.1
Total	1298.2			2085.9			742.8			4126.9		

APPENDIX D

IN THE MATTER OF MEETING THE REQUIREMENTS OF THE PROVINCE

As in the hearings preceding the Interim Report, each of the applicants submitted tabulations and/or statements indicating how, in their opinion, the future requirements of the Province might be met from known reserves. The applicants accepted the Interim Report estimate of the future requirements which is less by over 1 trillion cubic feet than the Board's revised estimate of about 4.1 trillion cubic feet. On the other hand, the applicants' estimates of the reserves from which these requirements were to be met were considerably greater than the Board's revised estimate of 6.8 trillion cubic feet.

For these reasons the applicants proposals as to the manner in which the Provincial requirements might be met require adjustment, upwards as to requirements and downwards as to reserves. In reviewing these proposals the Board has followed the method of illustrative deliverability schedules discussed in the Interim Report. In the light of new evidence on the matter, the Board has employed more generous deliverability estimates, particularly in the final years of the life of certain reserves. In most cases the deliverability schedules reflect well operation at rates increasing from 25% of absolute open flow early in the life of the field to over 50% near the end of the life.

The following Tables D-1, D-2, D-8 and D-10 are presented to show how the requirements might be met from the reserves now known. These schedules are believed to be realistic on the basis of present knowledge but cannot be interpreted too literally in view of the many contingencies involved.

The Area Tributary to The Canadian Western Natural Gas Company Limited System

Table D-1 presents, for the area tributary to the Canadian Western system, the future requirements, the manner in which fields now connected may be employed, and the "residual" requirements to be made up from fields not now connected. The annual and peak day requirements and the load factors previously shown in Table C-2 are presented in Columns 2, 3 and 4 of Table D-1.

Columns 5, 6 and 7 show the annual peak day quantities and the load factors which may be expected from the Turner Valley field. These figures include both the expected solution gas and gas cap gas production and are consistent with the revised reserve estimates. Both the annual and peak day amounts are increased over those presented in the Interim Report and indicate that the present peak day volume of 95 million cubic feet may be maintained for the next 9 to 10 years.

The figures for Jumping Pound are shown in columns 8, 9 and 10. Both the annual and the peak day quantities are revised from the Interim Report figures to take account of the revision in reserve estimate, a revision in contemplated plant size and the more generous field deliverability estimate. It has been assumed that the rated capacity of the plant will be increased from its present 25-20* million cubic feet per day to 31-25 million cubic feet per day in late 1952, 45-36 in 1953, 60-48 in 1954, and 62-50 in 1955 and thereafter. The peak day figures of column 9 from 1955 through 1964 have been taken at 10% over the rated capacity in the belief that a plant of this size will require an amount of standby equipment which would permit such over-capacity operation for a few days each year. The load factors of column 10 are based upon the actual peak days of column 9 and over the period 1955-1964, would exceed these figures by some 7% if based on rated capacity.

Columns11, 12 and 13 indicate the manner in which the presently connected Foremost field may be utilized primarily for the purposes of supplying peak requirements. These figures, while differing in detail, are essentially the same as those presented in the Interim Report. It is assumed that Bow Island will continue to serve entirely for peaking purposes and that off-peak gas from Turner Valley will be stored in this field. The peak day delivery volumes expected from Bow Island are shown in Column 14. The total peak day volumes for Foremost and Bow Island, i.e. the totals of columns 12 and 14, are in excess of the present delivery capacity of the connecting pipe line but

*The two figures used to express these capacities refer respectively to the plant intake of raw gas and the expected plant output of disposable gas.

are believed reasonable in the light of the increasing peak day requirements and the estimated delivery capacity of the two fields. The figures presuppose an almost immediate increase in the delivery capacity of the pipe line from its present 45 million cubic feet per day to some 60 million cubic feet per day.

Subtracting the projected annual and peak day delivery volumes of the presently connected fields of Turner Valley, Jumping Pound, Foremost and Bow Island, from the annual and peak day requirements of columns 2 and 3, leads to the "residual" annual and peak day requirements shown in columns 15 and 16 and the corresponding load factors shown in column 17. The presently connected fields are estimated as incapable of meeting the entire annual and peak day requirements from about 1955 onward. The residual annual requirements starting at 0.5 billion cubic feet in 1956 grow to an estimated 47 billion cubic feet in 1981, and aggregate over 650 billion cubic feet. The volumes by which the connected fields are incapable of meeting the peak day requirements become significant at some 15 million cubic feet per day in 1956 and grow to a maximum of some 280 million cubic feet per day at the end of the thirty year period. The load factor of the residual requirements shown in column 17, grows from less than 25% in 1956 to a maximum of over 45% in 1974.

It must be emphasized that this schedule is indicative only of one manner in which the reserves of the connected fields may be employed to meet the requirements. Other methods of field operation and development are possible and these would result in minor variations in the residual requirements shown in columns 15 and 16. For example, the expansion of facilities at Jumping Pound at earlier dates than suggested could defer the increase in the pipeline capacity to Foremost and Bow Island. Moreover the interruption of certain industrial loads on the few days of highest demand could also have the effect of deferring essential expansion either at Jumping Pound or in the storage fields and their connecting lines. It is believed, however, that the schedule is a reasonable one and that it takes into account the economics of plant operation and field development.

It may be noted that the total withdrawal from the Turner Valley field is some 330 billion cubic feet which is equivalent to the production of 95% of the estimated present disposable reserve of 346 billion cubic feet. In Jumping Pound the corresponding figures are 308 billion cubic feet, produced over the 30 year period, equivalent to 82% of the estimated present disposable reserve of 375 billion cubic feet. In the case of Foremost, which has been assumed to be used primarily for peak day demands, the total withdrawal in the 30 year period is estimated at 9 billion cubic feet or 43% of the estimated present disposable reserve of 21 billion cubic feet. Bow Island is utilized as a storage field for peak shaving purposes and merely serves to make excess summer gas production in Turner Valley available in the winter months. Thus, while the schedule is illustrative and subject to minor changes as to methods of operation, it is clear that with the resulting high percentage of production of the major fields, it would be difficult to conceive of a schedule which would result in lesser "residual" requirements.

The residual requirements detailed in columns 15 and 16 are greater than the corresponding figures shown in columns 22 and 23 of Table 5 in the Interim Report. The revised total residual requirement exceeds the Interim Report figure by some 45 billion cubic feet. When this is compared with the increase of 60 billion cubic feet shown in the revised requirements for the area tributary to the Canadian Western system it is apparent that the new schedule merely reflects the increased requirements with some modifications to compensate for differences in reserve estimates and in methods of operating fields.

The Area Tributary to the Northwestern Utilities Limited System

A similar illustrative deliverability schedule is presented in Table D-2 for the area tributary to the Northwestern Utilities system. This table indicates the future estimated requirements for this area, the manner in which the fields now connected (or about to be connected) may be employed, and the "residual" requirements to be made up from fields not presently connected. The annual and peak day requirements and the load factors previously shown in Table C-2 are listed in columns 2, 3 and 4 of Table D-2.

Columns 5, 6 and 7 indicate the annual and peak day delivery volumes and the load factor expected from the Leduc-Woodbend field. Columns 5 and 6 reflect the withdrawal of solution

gas from the D-3 pool and solution gas plus gas cap gas from the D-2 pool up until the mid 1960's. From that period forward increasing amounts of D-3 gas cap gas and Lower Cretaceous gas are assumed to become available. In the development of this projection weight was given to new evidence presented on behalf of Canadian Delhi Oil Ltd., and Trans-Canada Pipe Lines Limited by the consulting firm of DeGolyer and MacNaughton, as well as to previous evidence and up to date information in possession of the Board. The projection presupposes an increase in gas processing capacity. It is assumed that through the expansion of the present plant and/or the construction of new facilities the rated processing capacities available for Leduc-Woodbend gas would be increased from an estimated 24-21* million cubic feet per day from 1952 to 1954, through 40-35 million cubic feet per day in the period 1954 to 1956, to 60-52 million cubic feet per day thereafter. As in the case of Jumping Pound it has been assumed that the rated plant capacity might be exceeded by as much as 10% for a few days out of the year to meet the highest peaks. The estimated production figures for D-2 and D-3 solution gas and D-2 gas cap gas indicate that the field should be able to supply raw gas to meet the rated plant capacity for the period 1956 through 1966, but that thereafter the availability of raw solution gas will fall rapidly, declining to some 5 million cubic feet per day by 1974. It is assumed that at this time, i.e. about 1966, increasing volumes of D-3 gas cap gas could be produced to maintain plant operation at a proper level. While the Board has received conflicting information as to the probable economics of processing D-3 gas gap gas, it is of the opinion that this gas, when initially produced through high gas-oil ratio oil wells will be sufficiently rich in liquid hydrocarbons to warrant processing in the existing facilities. Moreover the Board believes that by the late 1960's the economic value of the recoverable components (the butanes, propane and perhaps ethane) may well be such as to favor their extraction even from relatively lean gases. (The recently announced construction of the National Petro-Chemicals Corporation plant near Tuscola, Illinois for the processing of a comparatively lean pipeline gas (6.53 per cent ethane, 4.15 per cent propane plus) is an indication of the economic possibilities where markets for ethane, and propane exist.)

In the period starting in the early 1970's it is estimated that the remainder of the D-3 gas-cap gas and the Lower Cretaceous gas reserves may both be produced at reasonably high rates—probably through depleted D-2 and D-3 oil wells. While the economics of processing the gas is not known at this time it has been assumed that the gas would be produced at relatively high load factor so that if processing is warranted it could be accomplished through the construction of further facilities. The figures of column 5 reflect from 1972 onward the withdrawal of some 42 billion cubic feet per year at 80% load factor.

Columns 8, 9 and 10 show the contemplated annual and peak day withdrawals and the resulting load factors for the group of fields listed in Table A-1 under the heading Morinville, Legal-Waybrook, Manawan Lake and Calahoo. This group of fields is not supplying the Northwestern Utilities area at present but a pipe line is being built to connect the Morinville field to the new Canadian Chemical Plant near Edmonton.

The Board has considered it advisable however, to group all these reserves and the requirements of the Canadian Chemical Company Limited with the others in the same natural area. The projection of Table D-2 for this group of fields was made somewhat arbitrarily but generally reflecting present arrangements between the Canadian Chemical Company Limited and the holders of the bulk of the Morinville area reserve.

Columns 11, 12 and 13 present the production projection for the Viking-Kinsella field which is now connected to the main market in the Northwestern Utilities area. This projection reflects the contemplated use of Viking-Kinsella for the purpose of meeting to the limit of its ability that part of the total requirement of the area which cannot be met from Leduc-Woodbend and the Morinville group. Accordingly, the annual and peak day figures which appear in columns 11 and 12 are those required to satisfy or partly satisfy the remainder of the requirements shown in columns 2 and 3. When employed in this manner, Viking-Kinsella is estimated to be capable of supplying the estimated peak day requirements only until about 1962 although it could supply the annual volumes until about 1968. Thereafter the Viking-Kinsella field is incapable of making up the difference between the total requirements and those which can be supplied from Leduc-Woodbend and Morinville. It might be mentioned that in the period 1952 through 1956, and with the contemplated drilling program, the peak delivery capacity of Viking-Kinsella is expected to be in excess of that actually

*The two figures used to express these capacities refer respectively to the plant intake of raw gas and the expectec plant output of disposable—the latter corrected to a 1000 B.T.U. basis.

required by the market. From 1956 until about 1962 an active drilling program will be required in Viking-Kinsella to develop its peak delivery capacity proportionate to the gain in peak requirments. It is assumed that the Viking-Kinsella field will be developed to its economic limit by about 1962 with some 175 wells.

The resulting residual requirements for the Northwestern Utilities area are presented in columns 14, 15 and 16. Column 14 indicates that annual residual requirements may be expected to become significant in about 1968 growing to some 50 billion cubic feet per year in 1981, and aggregating some 530 billion cubic feet. Column 15 shows the residual peak day requirement starting at approximately 4 million cubic feet per day in 1962 and growing to some 360 million cubic feet per day at the end of the 30 year period. The corresponding load factors are those tabulated in column 16.

Again it is to be stressed that Table D-2 reflects only one way in which the presently connected reserves may be employed to meet anticipated requirements. For example further developments, particularly the increased availability of solution gas, might indicate the desirability of employing fields in the Morinville area for the purposes of meeting peak loads. Also it is quite probable that Viking-Kinsella could be operated at lesser load factors during the mid-1960's, reflecting a decrease in the residual peak day requirement of column 15 but an earlier development of the residual annual requirement shown in column 14.

The schedule shows a total production from the Leduc-Woodbend field of some 713 billion cubic feet, equivalent to 83% of its present remaining disposable reserve estimated at 858 billion cubic feet. In the cases of both Morinville and Viking-Kinsella, the production schedule anticipates complete depletion of the presently known disposable reserves. Again, therefore, the relatively high percentage production of the available disposable gas suggests that alternate schedules, while changing the details, would not result in any significant lowering of the residual requirements shown in columns 14 and 15.

The Overall Magnitude of the Reserves Necessary to Meet the Residual Requirement of the Two Areas

An analysis of the size of the reserves necessary to meet the residual requirements of the two areas is helpful in a consideration of the manner in which these requirements and those of of the remainder of the Province can best be met from the present reserves.

In the case of the area tributary to the Canadian Western system the aggregate residual requirement is shown in Table D-1 to be some 650 billion cubic feet, and the peak day residual for 1981 is indicated as some 280 million cubic feet per day. A study of the relationship between maximum daily delivery capacity and remaining reserves of disposable gas for groupings of Alberta fields (Figure D-1) indicates that a remaining reserve of some 650 billion cubic feet would be necessary in 1981 to meet these peak day requirements. Accordingly the aggregate reserves necessary today to ensure the needed supply for the Canadian Western area are 650 billion cubic feet for the total residual requirement, and a further 650 billion cubic feet to meet the 1981 peak day load—or a total of some 1300 billion cubic feet.

Similar considerations for the Northwestern Utilities area indicate the need today of 530 billion cubic feet for the aggregate residual requirement and a further 820 billion cubic feet to meet the 1981 peak day load, or a total of some 1350 billion cubic feet.

In the case of both of these areas the requirement for meeting the 1981 peak day load has been estimated on the assumption of no peak shaving through storage projects. The Board has no doubts that storage projects could be employed advantageously and that they might serve to lessen the reserves necessary to meet the peak day load, albeit at some increase in the aggregate residual requirements. In the absence of any definite scheme, however, the Board is unable to estimate the degree of reduction in the total needed reserves which might so result.

Table D-3 has been compiled to indicate the presently known reserves which might be considered as sources of supply to meet the residual requirements of the Canadian Western area. Columns 1 and 2 indicate the names of the fields and the reserves at increasing straight line dis-

tances (colume 4) from Calgary, the market centre. Column 3 presents the cumulative reserves presently known within the radial distance corresponding to the entry in column 4. Column 5 shows, for the individual fields, the reserves available per shortest mile distance from the market centres. This figure may be considered as a preliminary index of the desirability of the field as a source of supply —although many other factors are of comparable importance. The tabulation shows that presently known reserves in the volumes necessary to meet the residual requirements of the Canadian Western area can be obtained only by reaching out a distance of at least 120 miles from the market centre. Within this radius the necessary 1300 billion cubic meet can only be assured from presently known

Table D-3

Possible Sources of Supply for the Residual Requirements of the Area Tributary to the Canadian Western Natural Gas Company Limited

1	2	3	4	5
Name of Field	Disposal Reserves billions of cubic feet	Cumulative Disposal Reserves billions of cubic feet	Shortest Distance to Calgary miles	Disposal Reserves per mile of shortest distance, billions of cubic feet per mile
Countess, Princess—Patricia Area	186	186	100	1.86
Cessford	440	626	100	4.40
Hanna	16	642	100	0.16
Stettler	12	654	100	0.12
Pincher Creek	1680	2334	120	14.00
Castor	34	2368	125	0.27
Oyen-Sibbald	31	2399	150	0.21
Medicine Hat-Dunmore	532	2931	160	3.33
**Pakowki Lake	*328	3259	170	1.93
Provost	84	3343	175	0.48

*372 - 43.8 presently granted five year export to Montana.

**Consists of Pendant d'Oreille and California Standard area, Manyberries, Black Butte and Smith Coulee.

reserves through the inclusion of the Pincher Creek field. In fact, from a reserve consideration alone, the Pincher Creek field itself would suffice. The market load factor, however, and producing and processing economics would favor the inclusion of at least one of the dry gas fields. Further consideration of Table D-3 indicates that within a radial distance of some 160 miles, which would include Medicine Hat-Dunmore, reserves of 2931 billion cubic feet could be obtained. Within this greater radius the necessary 1300 billion cubic feet could nearly be supplied without the connection of Pincher Creek.

The Board is forced to conclude, therefore, that the residual requirements of the area tributary to the Canadian Western system may be met from presently known reserves only by

(a) connecting the Pincher Creek field and one or more dry gas fields within a radius of 100-170 miles of Calgary;

(b) connecting virtually all presently known fields within a radius of approximately 160 miles of Calgary but excluding Pincher Creek.

Turning now to the case of the area tributary to the Northwestern Utilities system, Table D-4 has been compiled as the counterpart to Table D-3. This tabulation shows that presently known reserves in the volume necessary (i.e. some 1350 billion cubic feet) can be obtained only by reaching out a radial distance of at least 260 miles from Edmonton. Within this distance the necessary reserves can be acquired only by including all fields closer — even Stettler, Hanna, Cessford and Countess, Princess-Patricia, which are also within 100 miles of Calgary. It follows that if the area tributary to the Northwestern Utilities system is to be supplied from known reserves it must draw from those previously considered in connection with the Canadian Western area.

For this reason alternate (b) mentioned above is excluded as a present possibility for meeting the residual requirements of the Canadian Western area. Moreover it must presently be assumed that the dry gas fields referred to in alternate (a) will be required to serve both areas. This

Table D-4

Possible Sources of Supply for the Residual Requirements of the Area Tributary to the Northwestern Utilities Limited System

1	2	3	4	5
Name of Field	Disposable Reserves billions of cubic feet	Cumulative Disposable Reserves billions of cubic feet	Shortest Distance to Edmonton miles	Disposalbe Reserves per mile of shortest distance, billions of cubic feet per mile
Sturgeon	23	23	25	0.92
Picardville	23	46	42	0.55
Boyle-Mustang-Amisk Lake	37	83	75	0.49
Stettler	12	95	90	0.13
Castor	34	129	115	0.30
Hanna	16	145	150	0.11
Provost	84	229	165	0.51
Cessford	440	669	180	2.44
Oyen-Sibbald	31	700	195	0.16
Countess, Princess—Patricia Area	186	886	200	0.93
Tangent	131	1017	240	0.55
Whitelaw	316	1333	260	1.22
Medicine Hat-Dunmore	532	1865	270	1.97
Pincher Creek	1680	3545	300	5.60
Pouce Coupe	60	3605	310	0.19
**Pakowki	328*	3933	310	1.06

*372 - 43.8 presently granted five year export to Montana.

**Consists of Pendant d'Oreille and California Standard area, Manyberries, Black Butte and Smith Coulee.

approach leads logically to the conclusion that, from known reserves, the most reasonable method of meeting the residual requirements of both areas is through the combined reserves of those fields listed in Tables D-3 and D-4 which most economically can meet the combined residual requirements. It is the opinion of the Board that this could best be accomplished through the inter connection of both market areas and the reserves listed in Table D-5 following:

Table D-5

Presently Known Reserves Necessary to Meet the Estimated Residual Requirements of the Combined Canadian Western and Northwestern Utilities Areas

Field	Remarks	Reserve	Reserve per Shortest Distance to Edmonton	to Calgary
Cessford	essential to N.U. area	440	2.44	4.40
Countess, Princess—Patricia area	essential to N.U. area	186	0.93	1.86
Pincher Creek	essential to C.W. area	1680	5.60	14.00
Medicine Hat-Dunmore	best remaining field to make up necessary total	532*	1.97	3.33
Total		2838*		

*Less the local requirements of the Medicine Hat area.

The northern fields of Whitelaw and Tangent are not included in Table D-5. The Board believes that volumes of gas equivalent to the presently known reserves of these fields could be obtained more economically through an extension of the necessary line to the southern fields than by the construction of a separate long distance line in a northwesterly direction. From the viewpoint of known reserves, therefore, the connection of the fields of Table D-5 seem the most reasonable plan for meeting the residual requirements of the two major areas. Moreover when the problem of meeting the requirements of the remainder of the Province is considered this connection becomes the basis of the only plan the Board considers adequate under present circumstances.

In giving consideration to the requirements of the remainder of the Province the Board considered it advisable to segregate the requirements of the Peace River area and those of central, eastern and southern Alberta. This segregation appears appropriate from the viewpoint of the economic utilization of available reserves. Of the total of some 740 billion cubic feet, some 100 billion cubic feet may be attributed to the Peace River area and some 640 billion cubic feet to the central, eastern and southern areas. Similarly the 1981 peak day requirements are estimated as 33 million cubic feet for the Peace River area and 190 million cubic feet for the remainder of the Province. Remaining reserves of some 360 and 75 billion cubic feet are considered necessary to meet these respective 1981 peak day requirements. Thus to meet the requirement for the central, eastern and southern parts of the Province the Board estimates that a fotal of some 1000 billion cubic feet are necessary.

These requirements when added to the 2650 billion cubic feet of residual requirements for the Canadian Western and Northwestern Utilities areas, bring the total (excluding the Peace River area) to some 3650 billion cubic feet compared with the 2838 total of the four major fields listed above.

The difference of some 810 billion cubic feet must be met from fields other than those of Table D-5. Part of the requirement may logically be supplied from fields now connected, or likely to be connected to small communities. The fields shown in Table D-6 following are in this category.

Table D-6

Fields connected or likely to be connected to small communities

Name of field	Disposable Reserves billions of cubic feet
Athabasca	9.1
Battleview-Vermilion	12.0
Bonnyville	3.0
Brooks-Tilley	19.0
Brooks Northeast	4.6
Campbell	13.7
*Camrose	4
*Craigmyle	7
Elk Point	5.0
*Gadsby	3
*Jeffrey-Halfway Lake	9
Lac La Biche	12.6
Lloydminster	5.0
Redwater	2.0
*Spedden	2
St. Paul	3.0
Suffield	19.0
*Youngstown	5
Total	138, say 140

*Shown in Table A-1 under the heading of other small fields.

To meet the remaining some 670 billion cubic feet, from presently known reserves requires reserves in the volume equivalent to those of the remaining fields of Tables D-3 and D-4, shown in the following Table D-7:.

While the total of this latter group falls short of the estimated 670 billion cubic feet the difference is considered of little significance in view of the reserves of the many single well strikes which have not been estimated.

The main gathering lines for the two major market areas could facilitate the economic gathering and distribution of the reserves of this latter list, or of equivalent volumes of gas, to meet the requirements of the remainder of the Province.

In summary it is the Board's view that the requirements of central, eastern and southern Alberta including the areas tributary to the two major systems may be served best, from known re-

serves, through the development as needed of an extensive gathering grid. This grid would link the large reserves of Countess, Princess-Patricia, Cessford, Pincher Creek and Medicine Hat-Dunmore to the major markets and would gather gas from certain other fields as necessary to facilitate service to the areas not now served by the two major systems. Such a plan, however logically it may now appear, will necessarily be subject to extensive revision with the discovery and development of further reserves.

Table D-7

Remaining Fields of Tables D-3 and D-4 excluding those of the Peace River area

Name of field	Disposable reserves billions of cubic feet
Boyle-Mustang-Amisk Lake	37
Castor	34
Hanna	16
Oyen-Sibbald	31
**Pakowki	328*
Picardville	23
Provost	84
Stettler	12
Sturgeon	23
Total	588

*372 - 43.8 presently granted five year export to Montana.

**Consists of Pendant d'Oreille and California Standard area, Manyberries, Black Butte and Smith Coulee.

Illustrative Deliverability Schedule Showing the Manner in which the Residual Requirements May Be Met

It has been indicated that substantially all the reserves of the Province (except for those in the Peace River area) are required to meet the combined residual requirements of the Canadian Western area, the Northwestern Utilities area, and the remainder of the Province (excluding the Peace River area). A confirmatory and more detailed deliverability analysis is shown in Table D-8.

Details of the residual requirements of the two major areas and the requirements of the remainder of the Province (excluding the Peace River area) appear in columns 1 to 10 of Table D-8; columns 1 to 7 reproducing the figures from Table D-1 and D-2. Columns 8, 9 and 10 reflect the figures of columns 8, 9 and 10 in Table C-2 reduced by the estimated requirements of the Peace River area which would be better served directly from the northern fields. The details of the estimated requirements of the Peace River area are discussed later and presented in Table D-10. Columns 11, 12 and 13 show the total residual requirements of the south, central and eastern parts of the Province which must be met from presently known reserves.

The previous study has indicated also that the bulk of these requirements are probably best met from a gathering grid system. Accordingly, and in the interests of simplicity of presentation, the deliverability-reserve relationship for the many individual fields have been combined, first into logical geographical groupings, and finally into an overall composite. (The fact that these fields are considered in a single composite does not mean that they are assumed all to be interconnected—many definitely will not be.) Figure D-1 presents the estimated relationship between the daily delivery capacity and the remaining reserves of disposable gas for the composite group of fields of Tables D-5, D-6 and D-7, excluding Pincher Creek. The relationship labelled "maximum deliverability assuming complete development of known reserves" reflects the immediate development of all fields to the maximum number of wells considered economic, and the operation of these wells at initial rates of 25% of absolute open flow increasing to over 50% in the declining years. The dates shown on the relationship labelled "anticipated deliverability reflecting development as needed to meet requirements" reflect the delivery schedule to be discussed later. (Table D-9 shows the present and estimated maximum number of wells and the absolute open flows in terms of disposable gas for the **main** fields of the composite.) Pincher Creek has been excluded from the composite primarily because its delivery characteristics are influenced by plant capacity and other factors not in-

volved in the cases of the fields in the composite. Its estimated maximum delivery capacity and "anticipated deliverability as needed to meet requirements" are indicated in Figure D-2. Details of the assumed plant capacity are discussed below.

To supply the annual and peak day residual requirements for the Province as reflected in columns 11 and 12 production has been assumed from the composite group of fields as indicated in columns 14, 15 and 16. The composite group through a faster program of development than that shown in Figure D-1 could meet both the annual and peak day residual requirements of the Province until the year 1971 when it is estimated the peak day deliverability of the composite would be insufficient to meet the peak day demand. Columns 17, 18 and 19, however, reflect the introduction of gas from the Pincher Creek field in 1968, some three years before it would be absolutely essential. This is believed desirable in the interest of retarding the depletion of the composite group of fields thereby maintaining its peak delivery capacity on a higher level to meet the greatly increased peak requirements of the 1970's. Careful consideration has convinced the Board that, under presently known and estimated circumstances, the introduction of Pincher Creek gas at a much earlier date, when the volume and load factors are unattractive, would mean either uneconomic operation of the necessary processing and delivery facilities or expensive gas. It is to be noted that Column 14 shows an increasing production of the composite group of fields through the early and middle 1960's to 1968. Following this the annual withdrawal from the composite is reduced for a few years increasing to its 1967 level in about 1972 by which time the Pincher Creek load is assumed to have reached its maximum.

Column 17 reflects the annual production of Pincher Creek based upon the assumption of an initial plant having a rated capacity of 120-90* million cubic feet per day and operation at 10% overload for a few days during the year to meet the highest peaks. The actual load factor based upon peaks is taken as 68%. The load factor based upon rated plant capacity would be 7% above this or 75%. This load factor is believed reasonable and somewhere near the economic minimum for the operation of the high cost well and field installation and the expensive large scale plant which would be required. The rated plant capacities are assumed to increase through 187-140* million cubic feet per day in 1969 to 228-171* million cubic feet per day in 1970 to an ultimate of 265-200* million cubic feet per day in 1971.

The details presented for the years 1968 onward reflect the operation of the Pincher Creek field at a load factor of 75% based on rated capacity, with the composite group of fields supplying the remainder of both the annual and peak day residual requirements. Thus columns 14 and 15 are in fact obtained by difference, column 14 being the difference between column 11 and column 17, and column 15 being the difference between columns 12 and 18. The physical ability of the Pincher Creek field to deliver peak day quantities to the 220 million cubic feet per day figure shown in column 18 from 1971 on is maintained through the year 1981. At this time, however, the field is estimated to be depleted almost to the point at which it could no longer meet the required 220 million cubic feet per day—see Figure D-2. On the other hand, the composite fields maintain their abilities to meet the increasing peaks only until the late 1970's, (see Figue D-1) a peak deficiency of 23 million cubic feet per day occurring in 1977 and growing to 193 million cubic feet per day in 1981 as shown in column 20. The schedule indicates therefore that the composite group of fields plus Pincher Creek as presently known are capable of meeting the annual requirements shown in column 11 but are incapable of meeting the total peak day requirements shown in column 12 for the last five years of the thirty year period. The apparent shortage in peak day capacity in the last five years of the thirty year period is considered of no practical significance in the light of the several important individual well strikes (such as Shell MacKidd and Bailey Olds) whose reserves have not been estimated. Moreover this peak day shortage could be alleviated by the drilling of further wells. The Board considers that Table D-8, confirming the previous overall considerations, indicates that the estimated requirements for the thirty year period can be met from presently known reserves.

The schedule indicates a production over the thirty year period of approximately 712 billion cubic feet from Pincher Creek out of its estimated reserve of 1680 billion cubic feet, i.e. a production of only some 42% of the reserve in the producing period 1968 through 1981. In the case of the composite fields the schedule reflects production of some 1105 billion cubic feet out of an estimated 1884 billion cubic feet of presently known remaining reserve. This represents a production over a twenty-five year period of about 59% of the presently known reserve of these fields.

*The two figures used to express these capacities refer respectively to the plant intake of raw gas and the expected plant output of disposable gas.

These low percentage production figures might be taken as indicative of a rather slow utilization of the reserves. In the absence of a storage project which could alleviate the peak day requirements, however, it is almost essential to have a substantial percentage of the estimated recoverable reserves of both Pincher Creek and the composite fields left in the ground in 1981 in order to maintain deliverability.

Table D-8 shows one way in which the residual requirements of the Province may be met from known reserves. The schedule may not be the best that could be planned. Certainly it will never implement as such because new discoveries and unforseen circumstances will alter the premises on which it is based. For example, while it is presently suggested that production from Pincher Creek will be deferred until 1968, future developments may and probably will alter this. None the less, the schedule does show that if the present and future requirements of the Province are to be protected, virtually all gas south of Edmonton will be required. Re-arrangement of the producing schedule cannot significantly alter the fact that some 3650 billion cubic feet of gas not now connected to the large market areas must be dedicated to meet the residual requirements, nor the fact that the estimate for the combined reserves of the fields available at present is of this same order.

The Northern Fields

For reasons discussed earlier the group of fields in the Peace River area of the Province, including Whitelaw, Tangent and Pouce Coupe, have not been drawn into the composite nor employed to serve the residual requirements of the Canadian Western and Northwestern Utilities areas. These fields have an aggregate reserve presently estimated by the Board at 507 billion cubic feet. (The Valleyview field, estimated at 13.6 billion cubic feet, and Normandville included in Table A-1 at 3.5 billion cubic feet under the heading "Other Reserves," are presently considered beyond economic reach). They are the logical source of supply for the general Peace River area of Alberta and some gas from the Pouce Coupe field is already committed to serve Dawson Creek in British Columbia.

The estimated requirements of the Peace River area of Alberta and the present commitments from the Pouce Coupe field to British Columbia are shown in columns 2, 3, 4, 5 and 6 of Table D-10. The Board estimates that in the year 1960 the urban population of the Peace River area of Alberta will be some 15% of the urban population of the remainder of the Province, excluding that of the Canadian Western and Northwestern Utilities areas. On this basis the requirements shown in column 2 from 1960 to 1981 are estimated at 15% of those shown for the remainder of the Province in column 8 of Table C-2. The estimates for the period 1952 to 1960 are considered realistic in the light of probable load attachments during that period. Over the next twenty-nine year period 12.7 billion cubic feet of gas is committed from the Pouce Coupe field to Dawson Creek, B.C. Estimates of the annual amounts are shown in column 3. Column 4 represents the estimated total requirements of the Peace River area including Dawson Creek, B.C. and column 5 presents the corresponding peak day requirements assuming a 40% load factor as shown in column 6.

Columns 7, 8 and 9 show the estimated delivery capacity of a composite of the Whitelaw, Tangent and Pouce Coupe fields developed to the degree necessary to meet the requirements of the area. Column 10 shows the surplus delivery capacity of the composite assuming immediate complete development of the fields. The delivery characteristics are based upon the data listed in Table D-11 which in turn are reflected by the deliverability-reserves relationship of Figure D-3. Columns 7, 8 and 9 demonstrate the ability of these northern fields to meet the requirements shown in columns 4, 5 and 6 and, in fact, indicate a relatively large remaining reserve in 1981 of some 390 billion cubic feet. This remaining reserve is capable of meeting 1981 peak requirements considerably in excess of those shown in column 5. The excess peak day delivery capacity of the fully developed fields (as now known) is indicated in column 10. By computation the Board has determined that further removals of 312 billion cubic feet could be made, within the next few years, without prejudice to the meeting of the requirements of columns 4, 5 and 6. Column 11 indicates the year to year surplus peak day capacity of the fully developed fields assuming the immediate removal of the 312 billion cubic feet and shows that even with such a removal the estimated peak requirements for 1981 may be met.

Thus, out of the presently estimated reserves of 507 billion cubic feet, an estimated 195 billion cubic feet are required to meet the present and future needs of the area and a surplus of some 312 billion cubic feet of gas exists in the Pouce Coupe, Tangent and Whitelaw fields. To this figure may be added the reserve of 17 billion cubic feet presently estimated in the Valleyview and Normandville fields bringing the overall surplus to 329 billion cubic feet.

Table D-1

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE AREA TRIBUTARY TO THE CANADIAN WESTERN NATURAL GAS COMPANY LIMITED SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
	Total Requirements			Turner Valley			Jumping Pound			Foremost			Bow Island	Residual Requirements		
Year	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	PEAK DAY millions of cubic feet	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent
1952	26.2	179	40	19.2	95	55.3	6.7	25.0	74	0.3	15.5	5.3	43.5			
1953	27.9	191	40	18.8	95	54.2	8.8	36.0	69	0.3	15.3	5.4	44.7			
1954	29.6	203	40	17.7	95	51.0	11.6	48.0	64	0.3	15.0	5.5	45.0			
1955	31.2	214	40	18.3	95	52.8	12.6	55.0	63	0.3	14.7	5.6	45.3		4.0	
1956	32.8	225	40	17.9	95	51.6	14.1	55.0	70	0.3	14.5	5.7	45.5	0.5	15.0	9.3
1957	34.4	236	40	17.6	95	50.8	14.1	55.0	70	0.3	14.3	5.7	45.7	2.4	26.0	25.4
1958	35.9	246	40	17.8	95	51.3	14.1	55.0	70	0.3	14.1	5.8	45.9	3.7	36.0	28.1
1959	37.5	257	40	17.7	95	51	14.1	55.0	70	0.3	13.9	5.9	46.1	5.4	47.0	31.5
1960	38.9	266	40	17.7	95	51	14.1	55.0	70	0.3	13.7	6.0	46.3	6.8	56.0	33.2
1961	39.6	271	40	17.7	95	51	14.1	55.0	70	0.3	13.5	6.1	46.5	7.5	61.0	33.6
1962	40.4	277	40	16.1	86.5	51	14.1	55.0	70	0.3	13.3	6.2	46.7	9.9	75.5	35.9
1963	41.3	283	40	14.4	77.2	51	14.1	55.0	70	0.3	13.0	6.3	47.0	12.5	90.8	37.7
1964	42.1	288	40	12.9	69.2	51	14.1	55.0	70	0.3	12.8	6.4	47.2	14.8	103.8	39.0
1965	42.9	294	40	11.5	61.7	51	13.5	52.7	70	0.3	12.5	6.6	47.5	17.6	119.6	40.3
1966	43.7	299	40	10.3	55.2	51	12.6	49.4	70	0.3	12.3	6.7	47.7	20.5	134.4	41.8
1967	44.6	305	40	9.1	48.9	51	11.6	45.5	70	0.3	12.1	6.8	47.9	23.6	150.6	43.0
1968	45.5	312	40	8.3	44.8	51	11.0	42.9	70	0.3	11.9	6.9	48.1	25.9	164.3	43.2
1969	46.4	318	40	7.5	40.1	51	10.3	40.3	70	0.3	11.7	7.0	48.3	28.3	177.6	43.6
1970	47.3	324	40	6.8	36.3	51	9.6	37.7	70	0.3	11.5	7.1	48.5	30.6	190.0	44.1
1971	48.1	329	40	6.4	34.1	51	9.1	35.8	70	0.3	11.3	7.3	48.7	32.3	199.1	44.5
1972	48.8	334	40	6.0	32.2	51	8.5	33.2	70	0.3	11.1	7.4	48.9	34.0	208.6	44.6
1973	49.5	339	40	5.5	29.5	51	8.0	31.2	70	0.3	10.9	7.5	49.1	35.7	218.3	44.8
1974	50.2	344	40	5.1	27.6	51	7.3	28.6	70	0.3	10.7	7.7	49.3	37.5	227.8	45.1
1975	51.0	349	40	5.0	26.6	51	6.8	26.7	70	0.3	10.5	7.8	49.5	38.9	235.7	45.2
1976	51.7	354	40	4.6	24.7	51	6.5	25.4	70	0.3	10.3	8.0	49.7	40.3	243.9	45.3
1977	52.5	360	40	4.4	23.5	51	6.0	23.4	70	0.3	10.0	8.2	50.0	41.8	253.1	45.2
1978	53.3	365	40	4.1	21.8	51	5.6	22.1	70	0.3	9.8	8.4	50.2	43.3	261.1	45.4
1979	54.1	371	40	3.9	20.9	51	5.3	20.8	70	0.3	9.5	8.7	50.5	44.6	269.3	45.4
1980	55.0	377	40	3.6	19.5	51	5.0	19.5	70	0.3	9.3	8.9	50.7	46.1	278.0	45.4
1981	55.8	382	40	3.5	19.0	51	4.7	18.2	70	0.3	9.0	9.1	51.0	47.3	284.8	45.5
Total	1298.2				329.4		308.0			9.0			0	651.8		
Established Reserves Available for Disposition					346		375			21			16			
Percentage Withdrawn					95%		82%			43%			0%			

Table D-2

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE AREA TRIBUTARY TO THE NORTHWESTERN UTILITIES LIMITED SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Total Requirements			Leduc-Woodbend			Morinville, etc.			Viking Kinsella			Residual Requirements		
Year	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent
1952	24.0	178	37	6.7	23.0	80				17.3	155	30.6			
1953	36.3	221	45	6.7	23.0	80	12.8	36.9	95	16.8	161	28.6			
1954	42.9	245	48	11.1	38.3	80	12.8	36.9	95	19.0	170	30.6			
1955	47.0	268	48	11.1	38.3	80	14.7	42.4	95	21.2	187	31.1			
1956	51.7	289	49	16.8	57.4	80	16.4	47.3	95	18.5	184	27.5			
1957	57.0	312	50	16.8	57.4	80	17.1	46.8	100	23.1	208	30.4			
1958	59.1	324	50	16.8	57.4	80	14.9	40.7	100	27.4	226	33.2			
1959	61.5	344	49	16.8	57.4	80	12.8	35.2	100	31.9	252	34.7			
1960	63.7	356	49	16.8	57.4	80	11.1	30.3	100	35.8	269	36.5			
1961	64.8	362	49	16.8	57.4	80	9.5	25.9	100	38.5	279	37.8			
1962	66.1	369	49	16.8	57.4	80	8.5	23.3	100	40.8	284	39.3		4	
1963	67.5	377	49	16.8	57.4	80	7.2	19.6	100	43.5	259	46.0		41	
1964	68.8	385	49	16.8	57.4	80	6.1	16.7	100	45.9	236	53.3		75	
1965	70.2	392	49	16.8	57.4	80	5.4	14.8	100	48.0	210	62.6		110	
1966	71.6	400	49	16.8	57.4	80	4.7	13.0	100	50.1	187	73.4		143	
1967	73.0	408	49	16.8	57.4	80	4.3	11.8	100	51.9	158	90.0		181	
1968	74.5	417	49	16.8	57.4	80	3.7	10.0	100	47.8	131	100.0	6.2	219	7.8
1969	76.0	425	49	16.8	57.4	80	3.3	8.9	100	38.3	105	100	17.6	254	19.0
1970	77.6	434	49	16.8	57.4	80	2.5	6.7	100	35.0	96	100	23.3	274	23.3
1971	78.6	439	49	16.8	57.4	80	1.2	3.3	100	25.2	69	100	35.4	309	31.4
1972	79.7	446	49	29.5	100.9	80							50.2	346	39.7
1973	81.0	453	49	42.2	144.4	80							38.8	309	34.4
1974	82.2	460	49	42.2	144.4	80							40.0	316	34.7
1975	83.4	466	49	42.2	144.4	80							41.2	322	35.0
1976	84.8	474	49	42.2	144.4	80							42.6	330	35.3
1977	86.0	481	49	42.2	144.4	80							43.8	337	35.6
1978	87.2	488	49	42.2	144.4	80							45.0	344	35.8
1979	88.5	495	49	42.2	144.4	80							46.3	351	36.2
1980	89.9	503	49	42.2	144.4	80							47.7	359	36.4
1981	91.3	510	49	42.2	144.4	80							49.1	366	36.7
Total	2085.9			713.7			169.0			676.0			527.2		
Established Reserve Available for Disposition				858			169			676					
Percentage Withdrawn				83%			100%			100%					

Table D - 8

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE RESIDUAL REQUIREMENTS OF THE CANADIAN WESTERN AREA, THE NORTHWESTERN UTILITIES AREA AND THE REMAINDER OF THE PROVINCE

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	Residual Requirements C.W.N.G.			Residual Requirements N.U.L.			*Requirements—Remainder of Province			Total Residual Requirements			Composite of the Fields shown in Tables D-5, D-6 and D-7 excluding Pincher Creek			Pincher Creek			Deficiencies
Year	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	PEAK DAY millions of cubic feet
1952							10.0	68	40	10.0	68	40	10.0	68	40.0				
1953							12.6	86	40	12.6	86	40	12.6	86	40.0				
1954							13.6	93	40	13.6	93	40	13.6	93	40.0				
1955		4					14.7	101	40	14.7	105	40	14.7	105	38.4				
1956	0.5	15	9.3				15.7	108	40	16.2	123	40	16.2	123	36.1				
1957	2.4	26	25.4				16.7	114	40	19.1	140	40	19.1	140	37.4				
1958	3.7	36	28.1				17.7	121	40	21.4	157	40	21.4	157	37.3				
1959	5.4	47	31.5				18.6	127	40	24.0	174	40	24.0	174	37.8				
1960	6.8	56	33.2				19.5	134	40	26.3	190	40	26.3	190	37.9				
1961	7.5	61	33.6				19.7	135	40	27.2	196	40	27.2	196	38.0				
1962	9.9	76	35.9		4		20.1	138	40	30.0	218	40	30.0	218	37.7				
1963	12.5	91	37.7		41		20.5	140	40	33.0	272	40	33.0	272	33.2				
1964	14.8	104	39.0		75		20.9	143	40	35.7	322	40	35.7	322	30.4				
1965	17.6	120	40.3		110		21.3	146	40	38.9	376	40	38.9	376	28.4				
1966	20.5	134	41.8		143		21.8	149	40	42.3	426	40	42.3	426	27.2				
1967	23.6	151	43.0		181		22.2	152	40	45.8	484	40	45.8	484	25.9				
**1968	25.9	164	43.2	6.2	219	7.8	22.6	155	40	54.7	538	27.9	30.5	440	19.0	24.2	98	68	
1969	28.3	178	43.6	17.6	254	19.0	23.0	158	40	68.9	590	32.0	30.6	436	19.2	38.3	154	68	
1970	30.6	190	44.1	23.3	274	23.3	23.5	161	40	77.4	625	33.9	30.8	437	19.3	46.6	188	68	
1971	32.3	199	44.5	35.4	309	31.4	23.9	164	40	91.6	673	37.3	36.8	453	22.3	54.8	220	68	
1972	34.0	209	44.6	50.2	346	39.7	24.3	166	40	108.5	721	41.2	53.7	501	29.3	54.8	220	68	
1973	35.7	218	44.8	38.8	309	34.4	24.6	168	40	99.1	695	39.1	44.3	475	25.5	54.8	220	68	
1974	37.5	228	45.1	40.0	316	34.7	25.0	171	40	102.5	715	39.3	47.7	495	26.4	54.8	220	68	
1975	38.9	236	45.2	41.2	322	35.0	25.4	174	40	105.5	732	39.5	50.7	512	27.1	54.8	220	68	
1976	40.3	244	45.3	42.6	330	35.3	25.8	177	40	108.7	751	39.7	53.9	531	27.8	54.8	220	68	
1977	41.8	253	45.2	43.8	337	35.6	26.2	179	40	111.8	769	39.8	57.0	526	29.7	54.8	220	68	23
1978	43.3	261	45.4	45.0	344	35.8	26.6	182	40	114.9	787	40.0	60.1	503	32.7	54.8	220	68	64
1979	44.6	269	45.4	46.3	351	36.2	27.0	185	40	117.9	805	40.1	63.1	478	36.2	54.8	220	68	107
1980	46.1	278	45.4	47.7	359	36.4	27.3	187	40	121.1	824	40.3	66.3	455	39.9	54.8	220	68	149
1981	47.3	285	45.5	49.1	366	36.7	27.7	190	40	124.1	841	40.4	69.3	428	44.4	54.8	220	68	193
Total	651.8			527.2			638.5			1817.5			1105.6			711.9			
Established Reserve Available for Dispostion													***1884			1680			
Percentage Withdrawn													59%			42%			

*Excludes Peace River area, Alberta.

**Commencement of Grid System, connecting Pincher Creek field and the other fields of Tables D-5, D-6 and D-7.

***Amount remaining after deducting the present five year commitment of 43.8 billion cubic feet to Montana, U.S.A.

Table D - 9

BASIC DELIVERABILITY DATA FOR FIELDS OF TABLES D-5 AND D-7, EXCLUDING PINCHER CREEK

1	2	3	4	5
Name of Field	Zone	Present No. of Wells	Estimated No. of Wells with Field fully developed	Absolute Open Flow per Well Disposable Gas millions of cubic per day
Black Butte	Bow Island, Ellis and Ribbon	3	7	6.0
Boyle-Mustang-Amisk Lake	Lower Cretaceous sands	4	14	4.8
Castor	Viking	1	5	2.8
	Lower Cretaceous	1	3	14.0
Cessford	Viking	4	11	4.4
	Basal Colorado	9	63	7.2
	Sunburst	6	25	6.0
Countess	Bow Island	3	14	5.6
Dunmore	Bow Island and Ellis	4	5	6.8
Hanna	Viking	2	2	3.8
	Blairmore	2	2	9.6
	Madison	1	1	3.8
Manyberries	Upper and Lower Bow Island	6	11	22.0
Medicine Hat	Medicine Hat sand	71	230	2.6
Oyen	Viking	2	5	7.2
Pendant d'Oreille and California Standard area	Bow Island sands	11	56	14.0
Picardville	Viking	3	5	13.6
Princess-Patricia, Steveville	Basal Colorado	14	20	7.6
	Sunburst	8	14	7.2
Rainy Hills and Toronto	Jefferson	2	5	3.2
Provost	Viking	8	25	3.8
Sibbald	Viking	3	4	6.8
Smith Coulee	Bow Island	2	5	6.4
Stettler	Lower Cretaceous	2	2	7.6
Sturgeon	Basal Blairmore	2	3	7.6

Table D - 10

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE PEACE RIVER (ALBERTA) AREA AND DAWSON CREEK, BRITISH COLUMBIA

1	2	3	4	5	6	7	8	9	10	11
	Requirements of the Peace River (Alberta) area and Dawson Creek, B.C.					Composite of the Whitelaw, Tangent and Pouce Coupe Fields			(1) Surplus Delivery Capacity	(2) Surplus Delivery Capacity
Year	Peace River Area ANNUAL billions of cubic feet	Dawson Creek ANNUAL billions of cubic feet	Total ANNUAL billions of cubic feet	Total PEAK DAY millions of cubic feet	LOAD FACTOR per cent	ANNUAL billions of cubic feet	PEAK DAY millions of cubic feet	LOAD FACTOR per cent	PEAK DAY millions of cubic feet	PEAK DAY millions of cubic feet
1952	0.1	0.3	0.4	2.7	40	0.4	2.7	40	162	67
1953	0.6	0.3	0.9	6.2	40	0.9	6.2	40	159	64
1954	1.0	0.3	1.3	8.9	40	1.3	8.9	40	156	60
1955	1.4	0.3	1.7	11.6	40	1.7	11.6	40	153	57
1956	1.8	0.3	2.1	14.4	40	2.1	14.4	40	150	54
1957	2.2	0.4	2.6	17.8	40	2.6	17.8	40	146	50
1958	2.6	0.4	3.0	20.5	40	3.0	20.5	40	142	46
1959	3.0	0.4	3.4	23.2	40	3.4	23.2	40	139	43
1960	3.4	0.4	3.8	26.0	40	3.8	26.0	40	135	39
1961	3.5	0.4	3.9	26.7	40	3.9	26.7	40	133	37
1962	3.6	0.4	4.0	27.3	40	4.0	27.3	40	132	36
1963	3.6	0.4	4.0	27.3	40	4.0	27.3	40	131	35
1964	3.7	0.4	4.1	28.1	40	4.1	28.1	40	128	32
1965	3.8	0.5	4.3	29.5	40	4.3	29.5	40	124	30
1966	3.8	0.5	4.3	29.5	40	4.3	29.5	40	123	28
1967	3.9	0.5	4.4	30.1	40	4.4	30.1	40	122	26
1968	4.0	0.5	4.5	30.8	40	4.5	30.8	40	120	24
1969	4.1	0.5	4.6	31.5	40	4.6	31.5	40	118	22
1970	4.1	0.5	4.6	31.5	40	4.6	31.5	40	116	21
1971	4.2	0.5	4.7	32.2	40	4.7	32.2	40	115	20
1972	4.3	0.5	4.8	32.9	40	4.8	32.9	40	112	17
1973	4.4	0.5	4.9	33.6	40	4.9	33.6	40	110	14
1974	4.4	0.5	4.9	33.6	40	4.9	33.6	40	108	12
1975	4.5	0.5	5.0	34.2	40	5.0	34.2	40	106	10
1976	4.5	0.5	5.0	34.2	40	5.0	34.2	40	105	9
1977	4.6	0.5	5.1	34.9	40	5.1	34.9	40	103	7
1978	4.7	0.5	5.2	35.6	40	5.2	35.6	40	100	5
1979	4.8	0.5	5.3	36.3	40	5.3	36.3	40	98	3
1980	4.8	0.5	5.3	36.3	40	5.3	36.3	40	97	2
1981	4.9		4.9	33.6	40	4.9	33.6	40	97	0
Totals	104.3	12.7	117.0			117.0				
Established Reserve Available for Disposition						507				
Percentage Withdrawn						23%				

Note:

(1) Surplus delivery capacity, assuming complete development of the fields.
(2) Surplus delivery capacity, with complete development of the fields and immediate removal of 312 billion cubic feet, in addition to the Peace River, Dawson Creek area requirements.

Table D-11

BASIC DELIVERABILITY DATA FOR FIELDS OF THE PEACE RIVER AREA

1	2	3	4	5
Name of Field	Zone	Present No. of Wells	Estimated No. of Wells with Field fully developed	Absolute Open Flow Per Well Disposable Gas millions of cubic feet per day
Pouce Coupe	Peace River	4	15	14.0
Tangent	Peace River	2	6	3.8
	Gething	2	13	9.6
	Triassic	3	15	4.8
Whitelaw	Peace River	3	5	3.8
	Gething	4	13	9.6
	Triassic	2	19	4.8

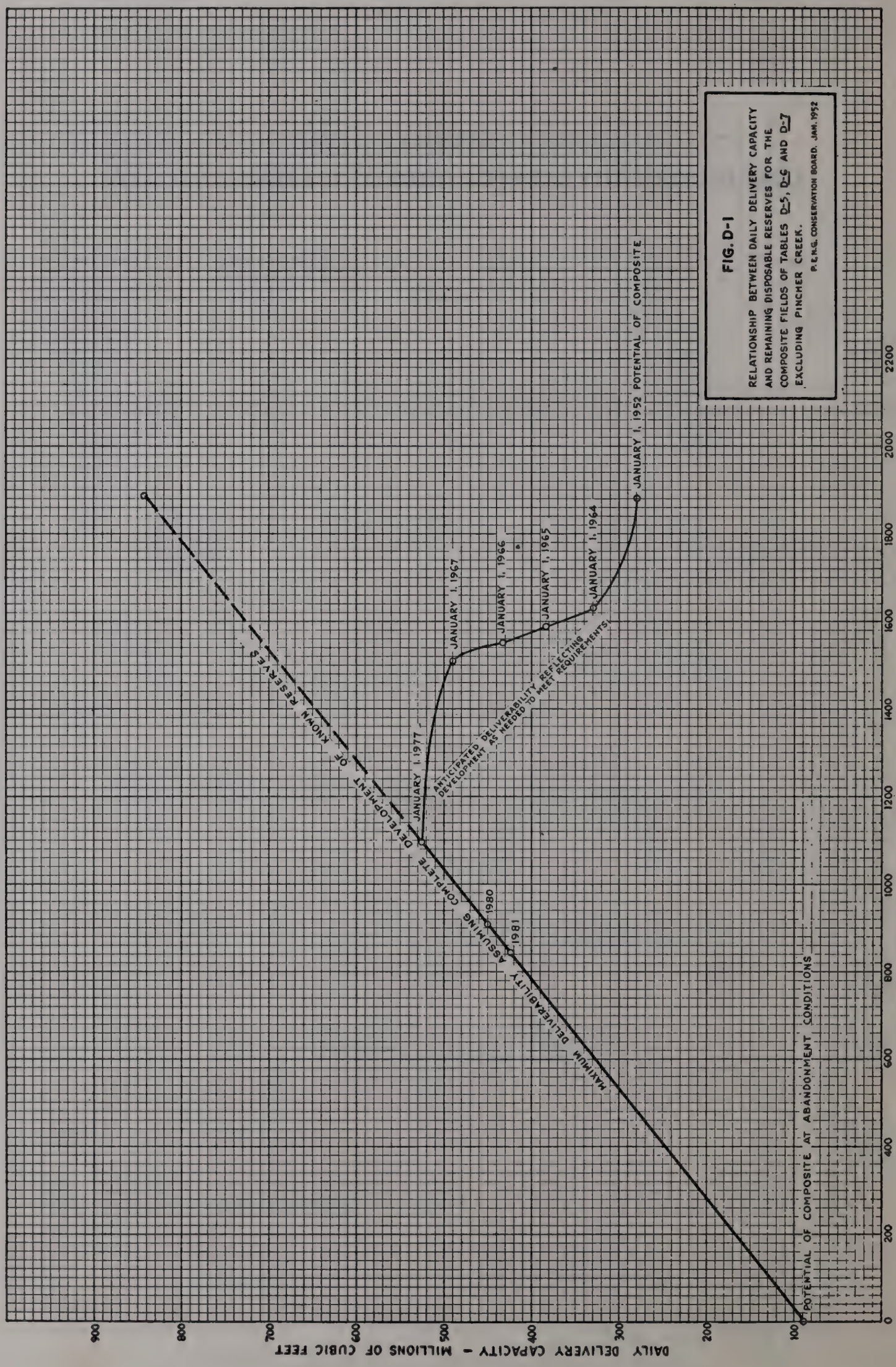


FIG. D-1
RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR THE COMPOSITE FIELDS OF TABLES D-5, D-6 AND D-7 EXCLUDING PINCHER CREEK.
P.E.N.G. CONSERVATION BOARD. JAN. 1952
DAILY DELIVERY CAPACITY — MILLIONS OF CUBIC FEET
REMAINING DISPOSABLE RESERVES — BILLIONS OF CUBIC FEET
POTENTIAL OF COMPOSITE AT ABANDONMENT CONDITIONS
MAXIMUM DELIVERABILITY ASSUMING COMPLETE DEVELOPMENT OF KNOWN RESERVES
ANTICIPATED DELIVERABILITY REFLECTING DEVELOPMENT AS NEEDED TO MEET REQUIREMENTS
JANUARY 1, 1952 POTENTIAL OF COMPOSITE
JANUARY 1, 1964
JANUARY 1, 1965
JANUARY 1, 1966
JANUARY 1, 1967
JANUARY 1, 1977
1981
1980

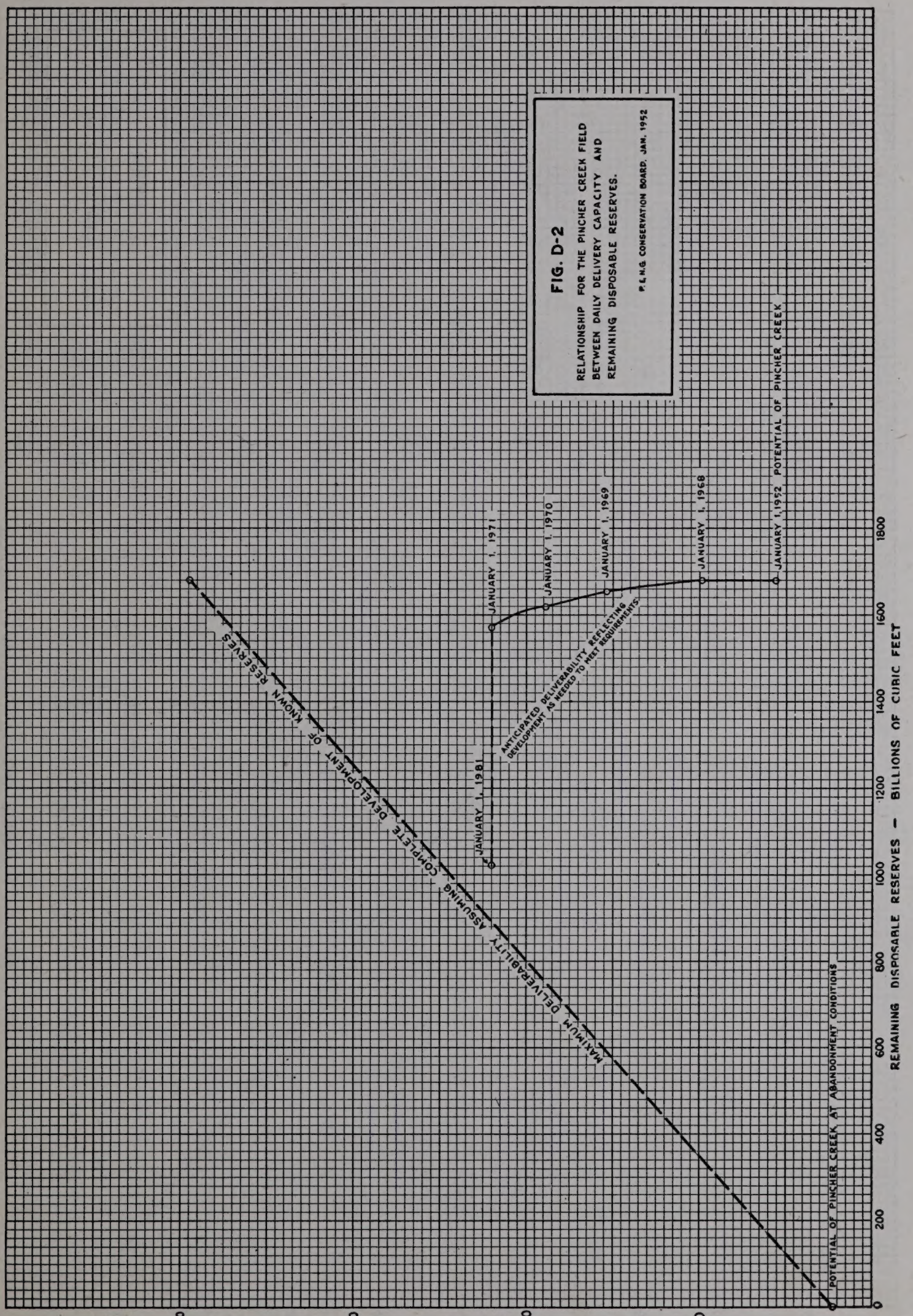


FIG. D-2
RELATIONSHIP FOR THE PINCHER CREEK FIELD BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES.
P.L.N.G. CONSERVATION BOARD, JAN. 1952
DAILY DELIVERY CAPACITY OF PINCHER CREEK — MILLIONS OF CUBIC FEET
REMAINING DISPOSABLE RESERVES — BILLIONS OF CUBIC FEET
0
100
200
300
400
0
200
400
600
800
1000
1200
1400
1600
1800
POTENTIAL OF PINCHER CREEK AT ABANDONMENT CONDITIONS
MAXIMUM DELIVERABILITY ASSUMING COMPLETE DEVELOPMENT OF KNOWN RESERVES
ANTICIPATED DELIVERABILITY REFLECTING DEVELOPMENT AS NEEDED TO MEET REQUIREMENTS
JANUARY 1, 1981
JANUARY 1, 1971
JANUARY 1, 1970
JANUARY 1, 1969
JANUARY 1, 1968
JANUARY 1, 1952 POTENTIAL OF PINCHER CREEK

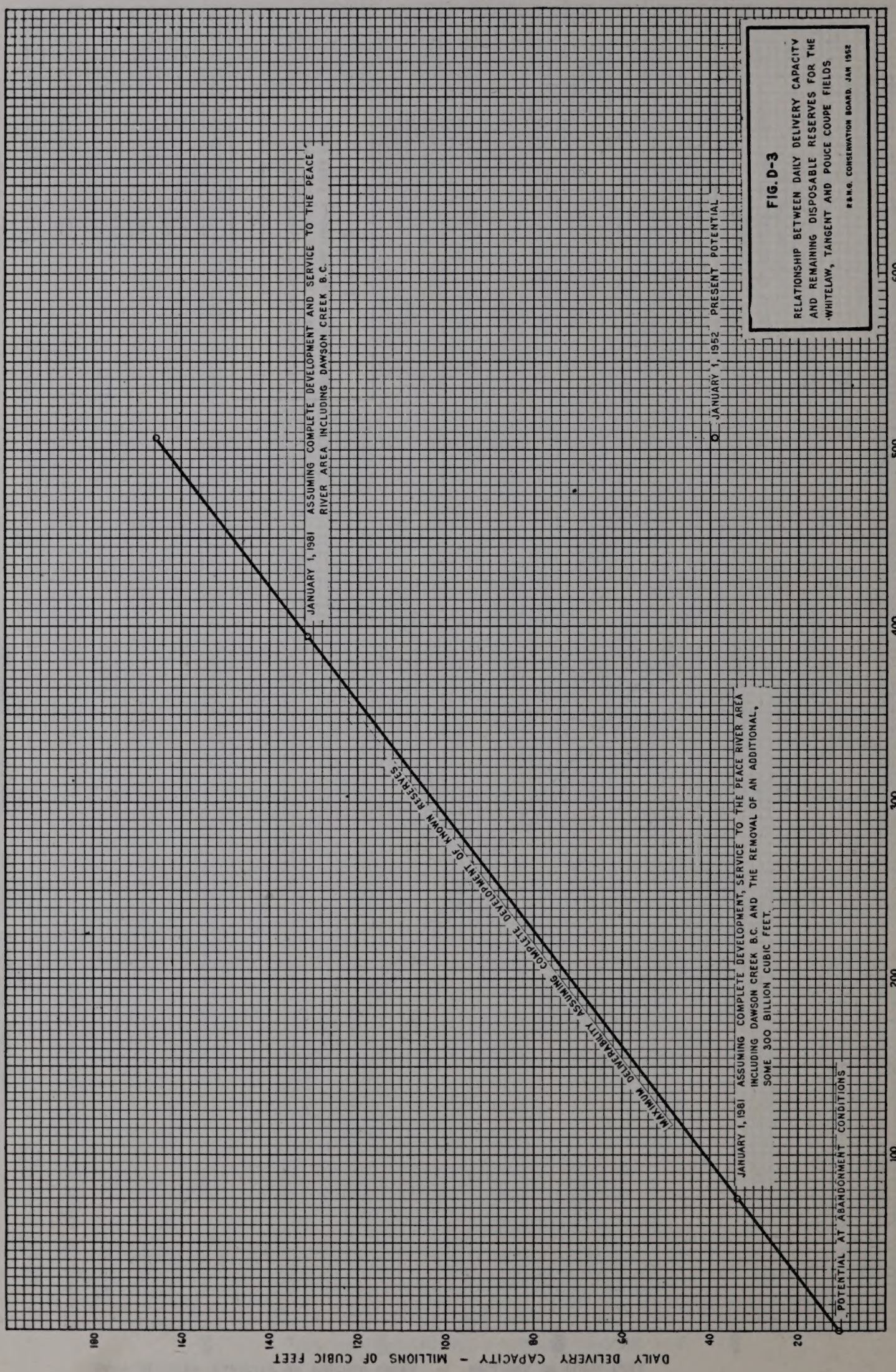

JANUARY 1, 1981 ASSUMING COMPLETE DEVELOPMENT AND SERVICE TO THE PEACE RIVER AREA INCLUDING DAWSON CREEK B.C.
JANUARY 1, 1952 PRESENT POTENTIAL
MAXIMUM DELIVERABILITY ASSUMING COMPLETE DEVELOPMENT OF KNOWN RESERVES
JANUARY 1, 1981 ASSUMING COMPLETE DEVELOPMENT, SERVICE TO THE PEACE RIVER AREA INCLUDING DAWSON CREEK B.C. AND THE REMOVAL OF AN ADDITIONAL, SOME 300 BILLION CUBIC FEET.
POTENTIAL AT ABANDONMENT CONDITIONS
DAILY DELIVERY CAPACITY - MILLIONS OF CUBIC FEET
REMAINING DISPOSABLE RESERVES - BILLIONS OF CUBIC FEET
20
40
60
80
100
120
140
160
100
200
300
400
500
600

FIG. D-3

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR THE WHITELAW, TANGENT AND POUCE COUPE FIELDS

P.&N.G. CONSERVATION BOARD. JAN 1952

Printed by
A. SHNITKA, Queen's Printer
1952
Edmonton, Alberta, Canada